138
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No. (1) 09-277

In The
Supreme Court of the United States

CONNECTICUT DEPARTMENT OF PUBLIC UTILITY CONTROL AND RICHARD BLUMENTHAL, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT,

Petitioners,

v.

FEDERAL ENERGY REGULATORY COMMISSION,

Respondent.

On Petition For A Writ Of Certiorari To The United States Court Of Appeals For The District Of Columbia Circuit

PETITION FOR A WRIT OF CERTIORARI

JOHN S. WRIGHT
MICHAEL C. WERTHEIMER
Assistant Attorneys General
OFFICE OF THE ATTORNEY GENERAL
10 Franklin Square
New Britain, CT 06051
(860) 827-2684

Counsel for Petitioner Richard Blumenthal, Attorney General for the State of Connecticut

RANDALL L. SPECK
Counsel of Record
KIMBERLY B. FRANK
LISA B. KATZ
REBECCA E. GRUNFELD
KAYE SCHOLER LLP
901 15th Street, NW
Washington, DC 20005
(202) 682-3510

Counsel for Petitioner Connecticut Department of Public Utility Control

COCKLE LAW BRIEF PRINTING CO. (800) 225-6964
OR CALL COLLECT (402) 342-2831

QUESTIONS PRESENTED FOR REVIEW

The Federal Power Act ("FPA") draws a "bright line" between federal and State regulatory jurisdiction. The plain language of the FPA precludes the Federal Energy Regulatory Commission ("FERC") (1) from regulating electricity generation facilities unless "specifically provided" or (2) from setting or enforcing compliance with standards for the adequacy, sufficiency, or reliability of electricity facilities or services to be furnished. 16 U.S.C. §§ 824(b)(1), 824f, 824o(i)(2)-(3). Nevertheless, FERC relies on its interpretation of the phrase "practices . . . affecting" jurisdictional rates in Section 205, 16 U.S.C. § 824d, to assert authority to set the amount of installed electric capacity that Connecticut must provide for adequate, reliable service – *i.e.*, the Installed Capacity Requirement ("ICR"). The questions presented are:

1. Should a court defer to FERC's interpretation of its jurisdiction under the FPA to set the amount of installed electric capacity that each State must provide for adequate, sufficient, reliable service?

2. Does FERC's asserted jurisdiction to set ICR as a "practice . . . affecting" wholesale rates encroach impermissibly on the States' traditional powers, which Congress preserved in the FPA, to determine the adequacy, sufficiency, and reliability of electric facilities or services to be furnished and to regulate generation facilities?

PARTIES TO THE PROCEEDINGS BELOW

Petitioner Connecticut Department of Public Utility Control was the petitioner in the U.S. Court of Appeals for the D.C. Circuit and a party before the Federal Energy Regulatory Commission. Petitioner Richard Blumenthal, Attorney General for the State of Connecticut, intervened in support of the petitioner in the Court of Appeals.

The Federal Energy Regulatory Commission was the respondent in the Court of Appeals and is therefore the respondent here under this Court's Rule 12.6.

The following parties before the Federal Energy Regulatory Commission intervened in support of the petitioner in the Court of Appeals: Maine Public Utilities Commission; Massachusetts Department of Public Utilities; and NSTAR Electric and Gas Corporation.

The following parties before the Federal Energy Regulatory Commission intervened in support of the respondent in the Court of Appeals: New England Power Pool Participants Committee; Boston Generating, LLC; Dominion Energy Marketing, Inc.; Dominion Energy New England, Inc.; Dominion Nuclear Connecticut, Inc.; Dominion Retail, Inc.; FPL Energy, LLC; Milford Power Company, LLC; Mirant Canal, LLC; Mirant Energy Trading, LLC; Mirant Kendall, LLC; NRG Power Marketing, LLC; Connecticut Jet Power, LLC; Devon Power, LLC; Norwalk Power, LLC; Middletown Power, LLC;

PARTIES TO THE PROCEEDINGS BELOW – Continued

Montville Power, LLC; Somerset Power, LLC; and ISO New England Inc.

The following party was granted leave by the Court of Appeals to intervene in support of the respondent: New England Power Generators Association, Inc.

TABLE OF CONTENTS

	Page
Questions Presented For Review	i
Parties To The Proceedings Below	ii
Table Of Contents	iv
Table Of Authorities	viii
Opinions Below	1
Statement Of Jurisdiction	1
Statutes And Regulations	2
Statement Of The Case	2
I. Statutory Framework	2
A. The Federal Power Act	2
B. The Energy Policy Act Of 2005	6
II. Installed Capacity Requirements	7
A. Defining Installed Capacity Requirements	7
B. States' Traditional Responsibility For Determining The Need For Electric Capacity	10
C. FERC's Treatment Of Installed Capacity Requirements	12
D. Installed Capacity Requirements And The Forward Capacity Market	14
III. Proceedings Below	15
A. Proceedings Before FERC	15
B. Proceedings In The Court Of Appeals	16

TABLE OF CONTENTS – Continued

Page

Reasons For Granting The Petition 17

I. The Court Of Appeals' Decision Conflicts With This Court's Guidance And The Rule In Other Circuits For Deference To An Agency's Interpretation Of Its Statutory Jurisdiction 22

A. The Court Of Appeals Improperly Deferred To FERC's View Of The Division Between State And Federal Jurisdiction When Congress Did Not Delegate Such Interpretative Authority To The Agency 22

B. The Court Of Appeals' Decision Disregarded Clear Statutory Limitations On Federal Jurisdiction 26

C. Contrary To This Court's Recent Holdings, The Court Of Appeals' Construction Of The FPA Gave Insufficient Weight To The Preservation Of Traditional State Powers 29

II. The Court Of Appeals' Decision Granting FERC Jurisdiction To Set ICR As A "Practice Affecting . . . Rates" Conflicts With This Court's Precedent And With The FPA's Unambiguous Reservation Of Jurisdiction To The States 32

TABLE OF CONTENTS – Continued

Page

A. This Court Has Rejected The Court Of Appeals' Expansive And Improper Interpretation Of "Practices Affecting . . . Rates" To Grant Jurisdiction That The FPA Otherwise Prohibits 32

B. The Court Of Appeals' Interpretation Of "Practices Affecting . . . Rates" As A Basis For Jurisdiction Would Require A Case-By-Case Determination Of FERC's Authority And Risks An Unbounded Expansion Of Federal Powers..... 36

III. The Court Of Appeals' Decision Raises An Issue Of Exceptional Importance Because It Threatens The States' Ability To Control Electricity Production Facilities Within Their Borders And Thereby To Protect Their Citizens' Health, Public Safety, And Welfare 38

Conclusion..... 40

Appendix A – Court of Appeals Opinion (June 23, 2009).....Pet. App. 1

Appendix B – Court of Appeals Judgment (June 23, 2009).....Pet. App. 20

Appendix C – FERC Order in Docket No. ER07-365-000, 118 FERC ¶ 61,157 (February 28, 2007).....Pet. App. 22

TABLE OF CONTENTS – Continued

Page

Appendix D – FERC Order on Rehearing in Docket No. ER07-365-002, 120 FERC ¶ 61,234 (September 14, 2007) ..... Pet. App. 84

Appendix E – FERC Order in Docket No. ER07-655-000, 119 FERC ¶ 61,161 (May 18, 2007) ..... Pet. App. 137

Appendix F – FERC Order on Rehearing in Docket No. ER07-655-001, 121 FERC ¶ 61,125 (November 1, 2007) ..... Pet. App. 158

Appendix G – FERC Order in Docket No. ER05-715-002, 122 FERC ¶ 61,144 (February 21, 2008) ..... Pet. App. 197

Appendix H – FERC Order on Rehearing in Docket No. ER05-715-003, 123 FERC ¶ 61,036 (April 17, 2008) ..... Pet. App. 211

Appendix I – Court of Appeals Order Denying Petitioner's Petition for Panel Rehearing (July 28, 2009) ..... Pet. App. 217

Appendix J – Court of Appeals Order Denying Petitioner's Petition for Rehearing *En Banc* (July 28, 2009) ..... Pet. App. 219

Appendix K – Relevant Statutory Provisions ..... Pet. App. 221

TABLE OF AUTHORITIES

Page

FEDERAL CASES:

Air Courier Conference of Am./Int'l Comm. v. U.S. Postal Serv., 959 F.2d 1213 (3d Cir. 1992) 25

ACLU v. FCC, 823 F.2d 1554 (D.C. Cir. 1987) 24

Barnhart v. Sigmon Coal Co., Inc., 534 U.S. 438 (2002) 27

Bolton v. Merit Sys. Prot. Bd., 154 F.3d 1313 (Fed. Cir. 1998) 24

Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc., 467 U.S. 837 (1984) 16, 20, 27

Conn. Dep't of Pub. Util. Control v. FERC, 484 F.3d 558 (D.C. Cir. 2007) 15

Conn. Dep't of Pub. Util. Control v. FERC, 569 F.3d 477 (D.C. Cir. 2009) ..... *passim*

Conn. Light & Power Co. v. FPC, 324 U.S. 515 (1945) 3, 10

Cuomo v. Clearing House Ass'n, 129 S. Ct. 2710 (2009) 29, 30

EEOC v. Seafarers Int'l Union, 394 F.3d 197 (4th Cir. 2005) 25

FDA v. Brown & Williamson Tobacco Corp., 529 U.S. 120 (2000) 27, 28

FPC v. Conway Corp., 426 U.S. 271 (1976) 6, 20, 34

FPC v. Panhandle E. Pipe Line Co., 337 U.S. 498 (1949) 20, 33, 36

TABLE OF AUTHORITIES – Continued

Page

FPC v. S. Cal. Edison Co., 376 U.S. 205 (1964) 2, 23, 38

Gustafson v. Alloyd Co., 513 U.S. 561 (1995) 32

La. Pub. Serv. Comm'n v. FCC, 476 U.S. 355 (1986) 28

Me. Pub. Utils. Comm'n v. FERC, 520 F.3d 464 (D.C. Cir. 2008), *cert. granted sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n*, 129 S. Ct. 2050 (2009) 7, 15

MCI Telecomms. Corp. v. AT&T, 512 U.S. 218 (1994) 35

Miss. Power & Light Co. v. Mississippi, 487 U.S. 386 (1988) 23

N. Ill. Steel Supply Co. v. Sec'y of Labor, 294 F.3d 844 (7th Cir. 2002) 24

Natural Res. Def. Council v. Abraham, 355 F.3d 179 (2d Cir. 2004) 24

New York v. FERC, 535 U.S. 1 (2002) 10, 23, 31

Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan., 489 U.S. 493 (1989) 20, 33

Okla. Natural Gas Co. v. FERC, 28 F.3d 1281 (D.C. Cir. 1994) 24

Otis Elevator Co. v. Sec'y of Labor, 921 F.2d 1285 (D.C. Cir. 1990) 24

Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n, 461 U.S. 190 (1983) 11, 31

TABLE OF AUTHORITIES – Continued

Page

Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n, 332 U.S. 507 (1947) 23

Rapanos v. U.S. Army Corps of Eng'rs, 547 U.S. 715 (2006) 30

Saipan Stevedore Co. Inc. v. Dir., Office of Workers' Comp. Programs, 133 F.3d 717 (9th Cir. 1998) 25

SEC v. Chenery Corp., 318 U.S. 80 (1942) 15

Social Sec. Bd. v. Nierotko, 327 U.S. 358 (1946) 23

Snell Island SNF LLC v. NLRB, 568 F.3d 410 (2d Cir. 2009) 24

United States v. Mead Corp., 533 U.S. 218 (2001) 22

Whitman v. Am. Trucking Ass'ns, Inc., 531 U.S. 457 (2001) 35

ADMINISTRATIVE CASES:

Devon Power LLC, 115 FERC ¶ 61,340 (2006) 7, 9

ISO New England Inc., 112 FERC ¶ 61,254 (2005) 14, 15

ISO New England Inc., 118 FERC ¶ 61,157 (2007) 1, 5, 15

ISO New England Inc., 119 FERC ¶ 61,161 (2007) 1, 5, 15

ISO New England Inc., 120 FERC ¶ 61,234 (2007) 1, 5, 8, 9, 16

TABLE OF AUTHORITIES -- Continued

Page

ISO New England Inc., 121 FERC ¶ 61,125 (2007) 1, 16

ISO New England Inc., 122 FERC ¶ 61,144 (2008) 1, 5, 15

ISO New England Inc., 123 FERC ¶ 61,036 (2008) 1, 16

ISO New England Inc., 123 FERC ¶ 61,290 (2008) 7

Midwest Indep. Transmission Sys. Operator, Inc., 103 FERC ¶ 61,210 (2003) 13, 14

New England Power Pool, 83 FERC ¶ 61,045 (1998) 9

NSTAR Elec. & Gas Corp. v. New England Power Pool, 103 FERC ¶ 61,093 (2003) 14

Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities, 75 FERC ¶ 61,680 (1996), 61 Fed. Reg. 21,540 (May 10, 1996) 10

Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, 100 FERC ¶ 61,138 (2002), 67 Fed. Reg. 55,452 (Aug. 29, 2002) 12, 13

TABLE OF AUTHORITIES – Continued

Page

Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, 112 FERC ¶ 61,073 (2005), 70 Fed. Reg. 43,140 (July 26, 2005) 13

Restructuring of the Elec. Indus., 163 P.U.R. 4th 1 (Conn. DPUC 1995) 10

Wholesale Competition in Regions with Organized Electric Markets, 128 FERC ¶ 61,059 (2009), 74 Fed. Reg. 37,776 (July 29, 2009) 37

FEDERAL STATUTES:

15 U.S.C. § 717 (2006) 33

15 U.S.C. § 717c (2006) 33

Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594 6

Federal Power Act, tit. II, ch. 687, 49 Stat. 803 (1935) (codified, as amended, at 16 U.S.C. §§ 824 *et seq.* and 825 *et seq.*) 2

16 U.S.C. § 824 (2006) ..... *passim*

16 U.S.C. § 824a (2006) 4, 5, 26, 30

16 U.S.C. § 824b (2006) 5, 26

16 U.S.C. § 824d (2006) 5, 6, 15, 33

16 U.S.C. § 824e (2006) 5, 17, 27

16 U.S.C. § 824f (2006) 4, 18, 26, 29, 30

TABLE OF AUTHORITIES – Continued

Page

16 U.S.C. § 824o (2006).....7, 18, 26, 28, 31

16 U.S.C. § 825 (2006) 5, 26

16 U.S.C. § 825b (2006).....5, 26

16 U.S.C. § 825*l* (2006) 16

28 U.S.C. § 1254 (2006) 2

STATE STATUTES:

CONN. GEN. STAT. § 16-19aa (2009) 12

CONN. GEN. STAT. § 16-19ss (2009).....12

CONN. GEN. STAT. § 16-50p (2009) 12

CONN. GEN. STAT. § 16-50r (2009).....12

CONN. GEN. STAT. § 16-244 (2009) 12

CONN. GEN. STAT. § 16a-3a (2009) 11

CONN. GEN. STAT. § 16a-3b (2009) 11

CONN. GEN. STAT. § 16a-3c (2009).....11

ME. REV. STAT. ANN. tit. 35-A, § 3210-D (2008) 12

MASS. GEN. LAWS ch. 164, § 69I (2009).....12

N.H. REV. STAT. ANN. § 162-H:1 (2009) 12

R.I. GEN. LAWS § 42-98-2 (2008) 12

VT. STAT. ANN. tit. 30, § 202a (2008) 12

TABLE OF AUTHORITIES – Continued

Page

LEGISLATIVE HISTORY:

H.R. REP. No. 74-1318 (1935) 10

S. REP. No. 74-621 (1935) 10

OTHER AUTHORITIES:

Antonin Scalia, *Judicial Deference to Administrative Interpretations of Law*, 1989 DUKE L.J. 511 (1989) 23

Clark Byse, *Judicial Review of an Administrative Interpretation of Statutes: An Analysis of Chevron's Step Two*, 2 ADMIN. L.J. 255 (1988) 22

J. Alexander Cooke, *The Resource Adequacy Requirement in FERC's Standard Market Design: Help for Competition or a Return to Command and Control?*, 20 YALE J. ON REG. 431 (2003) 9

Nathan A. Sales and Jonathan H. Adler, *The Rest is Silence: Chevron Deference, Agency Jurisdiction, and Statutory Silences*, 2009 U. ILL. L. REV. 102 (forthcoming, 2009), *available at* http://law.case.edu/faculty/adler_jonathan/articles/Silence-proof.pdf 19, 25

Stephen Breyer, *Judicial Review of Questions of Law and Policy*, 38 ADMIN. L. REV. 363 (1986) 22

WEBSTER'S NEW INTERNATIONAL DICTIONARY OF THE ENGLISH LANGUAGE (2d ed. 1934) 35

PETITION FOR WRIT OF CERTIORARI TO THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

The Connecticut Department of Public Utility Control (the "Department") and Richard Blumenthal, Attorney General for the State of Connecticut, (collectively, "Connecticut") respectfully petition for a writ of certiorari to review the judgment of the United States Court of Appeals for the District of Columbia.

OPINIONS BELOW

The opinion of the Court of Appeals (Pet. App. 1-19) is reported at 569 F.3d 477. The orders of the Federal Energy Regulatory Commission ("FERC") (Pet. App. 22-83, 137-157, and 197-210) are reported at 118 FERC ¶ 61,157, 119 FERC ¶ 61,161, and 122 FERC ¶ 61,144, and the orders denying rehearing (Pet. App. 84-136, 158-196, and 211-216) are reported at 120 FERC ¶ 61,234, 121 FERC ¶ 61,125, and 123 FERC ¶ 61,036.

STATEMENT OF JURISDICTION

The Court of Appeals entered its judgment on June 23, 2009. Pet. App. 20-21. The Court denied rehearing and rehearing *en banc* on July 28, 2009.

Pet. App. 217-220. This Court's jurisdiction is invoked under 28 U.S.C. § 1254(1) (2006).

STATUTES AND REGULATIONS

Relevant portions of the Federal Power Act, tit. II, ch. 687, 49 Stat. 803, 838-63 (1935) (codified, as amended, at 16 U.S.C. §§ 824-824w and 825-825u (2006)), are set forth at Pet. App. 222-263. Relevant portions of pertinent State statutes are set forth at Pet. App. 276-315.

STATEMENT OF THE CASE

I. STATUTORY FRAMEWORK

A. The Federal Power Act

This case is about Congress' preservation of States' rights to make decisions about the quantity of electricity production – *i.e.*, generation – facilities needed to provide adequate service. The FPA establishes a dual jurisdictional structure, assigning some defined areas of electricity regulation to FERC but otherwise prohibiting federal intrusion into the States' domain. Rather than a case-by-case determination of State or federal jurisdiction based on a general standard, the FPA defines a "bright line" of demarcation. *See FPC v. S. Cal. Edison Co.*, 376 U.S. 205, 215-16 (1964) ("Congress meant to draw a bright line easily ascertained, between state and federal

jurisdiction, making unnecessary such case-by-case analysis").

Section 201(a) shapes the over-arching framework by carving out the States' reserved jurisdiction from the specifically delineated federal scope, declaring

> that Federal regulation of matters relating to generation to the extent provided in this subchapter [16 U.S.C. §§ 824 *et seq.*] and subchapter III of this chapter [16 U.S.C. §§ 825 *et seq.*] and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

16 U.S.C. § 824(a); *see Conn. Light & Power Co. v. FPC*, 324 U.S. 515, 527 (1945) (finding that "such a declaration is relevant and entitled to respect as a guide in resolving any ambiguity or indefiniteness in the specific provisions which purport to carry out its intent," and "[i]t cannot be wholly ignored"). Congress further prescribed in Section 201(b) that

> [t]he Commission *shall have jurisdiction* over all facilities for such transmission [of electricity in interstate commerce] or sale of electric energy [at wholesale in interstate commerce], *but shall not have jurisdiction*,

> except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy . . . .

16 U.S.C. § 824(b)(1) (emphasis added).

Congress stressed this prohibition on FERC's jurisdiction over generation facilities. Section 202(b) plainly declares that FERC "shall have no authority to compel the enlargement of generating facilities . . . ." *Id.* § 824a(b). Similarly, Section 207 defines narrow circumstances when FERC can "[o]rder[ ] furnishing of adequate service."

> Whenever the Commission, upon complaint of a State commission, . . . shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: *Provided*, That the Commission *shall have no authority to compel the enlargement of generating facilities for such purposes* . . . .

Id. § 824f (emphasis added).

As foreshadowed by the exception in Section 201(b)(1), Congress did "specifically provide" for FERC jurisdiction over generating facilities in certain expressly identified, exceptional circumstances. For example, during a war, when "the Commission determines that an emergency exists by reason of . . . a shortage of electric energy or of facilities for the

generation or transmission of electric energy," Section 202(c) grants FERC authority to require "such generation . . . as in its judgment will best meet the emergency and serve the public interest." *Id.* § 824a(c). Section 203(a)(1) requires a public utility to obtain a FERC order authorizing it to "purchase, lease, or otherwise acquire an existing generation facility" if the facility meets a minimum threshold value and is used for interstate wholesale sales. *Id.* § 824b(a)(1)(D). Section 301 requires public utilities to make and keep accounts and records for generation facilities, *id.* § 825(a), and Section 303 makes FERC's reporting and depreciation requirements applicable to United States governmental agencies' generation facilities that produce electric energy for ultimate distribution to the public. *Id.* § 825b. These explicit exceptions delimit the comprehensive proposition that FERC "shall not have jurisdiction . . . over facilities used for the generation of electric energy . . . ." *Id.* § 824(b)(1).

FERC does not rely on the FPA's jurisdictional framework in Sections 201 or 202 but instead claims authority to set the Installed Capacity Requirement ("ICR") in New England because it is a "practice" "affecting . . . rates" under Section 205:[1] "All rates and

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[1] The Court of Appeals mistakenly relies on FPA Section 206, 16 U.S.C. § 824e(a), for FERC's jurisdiction over practices affecting rates. *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009) ("*Conn. Dep't II*") (Pet. App. 18). These proceedings arise, however, under Section 205, 16 U.S.C. § 824d. *See* Pet. App. 86, 147-48, 200-01. Both Sections 205 and

(Continued on following page)

charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable . . . ." *Id.* § 824d(a). Section 205 further provides that FERC may require every public utility to file "schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services." *Id.* § 824d(c).

B. The Energy Policy Act Of 2005

Section 1211 of the Energy Policy Act of 2005 amended the FPA to bolster the reliability of the "bulk-power system" and to create an Electric Reliability Organization. Pub. L. 109-58, 119 Stat. 594, 941-46 (codified at 16 U.S.C. § 824o). Congress made clear, however, that while the "bulk-power system" includes "electric energy from generation facilities needed to maintain transmission system reliability," the term "reliability standard" "does *not* include any requirement to enlarge [existing generation] facilities

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206 include similar, but not identical, language permitting FERC to *consider* practices affecting jurisdictional rates when assessing the justness and reasonableness of rates. *See FPC v. Conway Corp.*, 426 U.S. 271, 280-82 (1976); *infra* at 34.

or to construct new . . . generation capacity." 16 U.S.C. § 824o(a)(1), (3) (emphasis added). Congress further emphasized that this amendment "does not authorize the [Electric Reliability Organization] or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy . . . of electric facilities or services." *Id.* § 824o(i)(2). Moreover, "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard . . . ." *Id.* § 824o(i)(3).

II. INSTALLED CAPACITY REQUIREMENTS

A. Defining Installed Capacity Requirements

ICR is a reliability standard that specifies the number of megawatts of electric production capability deemed sufficient to provide adequate electric service. This "resource adequacy measure[ ]," *ISO New England Inc.*, 123 FERC ¶ 61,290 (2008) at P 27, identifies "the total amount of capacity required by the system to meet peak [demand] plus a reserve margin," *Devon Power LLC*, 115 FERC ¶ 61,340 (2006) at P 201 n.177, or "the minimum level of [electric production] capacity that is necessary to maintain reliability on the grid." *Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 469 (D.C. Cir. 2008),

cert. granted sub nom. NRG Power Mktg., LLC v. Me. Pub. Utils. Comm'n, 129 S. Ct. 2050 (2009). "Capacity" is "the ability to produce electric energy to serve load, when called by" the regional system operator. Pet. App. 100.

Resource adequacy measures like ICR may be developed using a variety of assumptions, including planned and unplanned generation facility outages, estimates for anticipated load growth, and the postulated benefits of relying on generation capacity from neighboring electrical systems. From a technical, reliability standpoint, ICR is not a single, empirically derived data point – *i.e.*, there can be "More Than One Acceptable Resolution" for ICR, and "two solutions to a technical issue are acceptable." JA 331. Thus, although a range of megawatt amounts can reasonably satisfy all objective reliability planning criteria, one end of that range may be patently unreasonable when assessed within the context of the resulting costs or State policy considerations. Under FERC's currently authorized process for New England, however, the regional system operator "determines the values it will file with the Commission," JA 9, notwithstanding whether the States concur.

Once the regional system operator fixes ICR and files it with FERC, the ICR becomes a mandatory obligation that each State's public utilities must provide. The ICR also sets an individual State's "Local Sourcing Requirement," *i.e.*, "the minimum amount of resources that an import-constrained zone

[like Connecticut] must maintain in order to meet reliability needs." JA 14. *See* JA 24; *Devon Power LLC*, 115 FERC ¶ 61,340 at P 121 (the Local Sourcing Requirement is the portion of the ICR "that must be obtained within each zone," *e.g.*, within Connecticut). FERC characterizes ICR as "the amount of resources [public utilities] *must provide* (which leads ultimately to a determination of the amount of resources each individual state's [public utilities] *must provide*) . . . ." Pet. App. 99-100 (emphasis added).

ICR has been generally characterized as "generating capacity." *See, e.g.*, *New England Power Pool*, 83 FERC ¶ 61,045, 61,262 (1998) (equating ICR with "the amount of installed *generation* that is needed to meet loads in [New England]") (emphasis added); JA 115 (defining ICR as "a measure of the installed *generating* capability," "the amount of *generating* capacity needed to meet the reliability requirements," and "the amount of *generating* capacity needed in New England") (emphasis added). The ICR may be satisfied by either generation facilities or enforceable demand reduction, but generation facilities have historically provided virtually all of New England's capacity. JA 124 (98% of capacity supplied by generation facilities). Given their overwhelming predominance as the way public utilities must meet their ICR obligations, constructing new generation facilities to meet ICR is effectively an "imperative." *See* Pet. App. 13; *see also* J. Alexander Cooke, *The Resource Adequacy Requirement in FERC's Standard Market Design: Help for*

Competition or a Return to Command and Control?, 20 YALE J. ON REG. 431, 453 (2003) (concluding that the suggestion that ICR does not directly regulate "generation capacity" is "a sleight of hand" attempt "to evade the FPA's explicit restrictions").

B. States' Traditional Responsibility For Determining The Need For Electric Capacity

In enacting the FPA, Congress observed that "[p]robably, no bill in recent years has so recognized the responsibilities of State regulatory commissions as does title II of this bill." *Conn. Light & Power*, 324 U.S. at 526 (quoting H.R. REP. NO. 74-1318, at 8 (1935)). The statute "removed every encroachment upon the authority of the States," and "[t]he limitation on the Federal Power Commission's jurisdiction in this regard has been inserted in each section [of the FPA] in a effort *to prevent the expansion of Federal authority over State matters*." S. REP. NO. 74-621, at 18 (1935) (emphasis added). One well-recognized State responsibility in 1935 was to assure the availability and reliability of electric production facilities. *See Restructuring of the Elec. Indus.*, 163 P.U.R. 4th 1, 10 (Conn. DPUC 1995) (reporting that through the 1930s, Connecticut's electric regulation agency focused on availability and reliability). Indeed, this Court and FERC have recognized "traditional state regulatory authority" over "most power production." *New York v. FERC*, 535 U.S. 1, 12 n.9 (2002) (quoting *Promoting Wholesale*

Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities, 75 FERC ¶ 61,680 (1996), 61 Fed. Reg. 21,540, 21,626 (May 10, 1996)). States have historically regulated "electricity production," "determin[ed] questions of need, reliability, cost and other related state concerns," "regulated for many years and in great detail" the "economic aspects of electrical generation," determined the "[n]eed for new power facilities," made "the initial decision regarding the need for power," and "exercise[d] their traditional authority over the need for additional generating capacity . . . ." *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 194, 205-06, 212 (1983).

Not surprisingly, therefore, Connecticut statutes charge its regulators with precisely these responsibilities. For example, the "Connecticut Energy Advisory Board" must "review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources," assess "the energy and capacity requirements of customers for the next three, five and ten years," and develop a State procurement plan that specifies "the total amount of energy and capacity resources needed to meet the requirements of all customers." CONN. GEN. STAT. §§ 16a-3a, 16a-3b, and 16a-3c (2009). The General Assembly has directed the Department to "determine the level of [a utility's] reserve capacity," to reduce that reserve capacity requirement when justified, and to solicit additional generating facilities as needed to assure adequate

service. *Id.* §§ 16-19aa(a), 16-19ss(a). The Connecticut Siting Council must prepare annual resource plans and forecasts and must make a finding of public need to site any new generation facility, *i.e.*, the facility must be necessary to assure the reliability of Connecticut's electric power supply. *Id.* §§ 16-50p, 16-50r. It is State policy to "encourage and allow for a sufficient number of in-state generating facilities to ensure an adequate and reliable power supply within the state . . . ," and "assurance of safe, reliable and available electric service to all customers" is an "essential governmental objective." *Id.* §§ 16-244(7)-(8). Other New England States – like most States – have similar regulatory directives. *See, e.g.*, ME. REV. STAT. ANN. tit. 35-A, § 3210-D (2008); R.I. GEN. LAWS § 42-98-2 (2008); MASS. GEN. LAWS ch. 164, § 69I (2009); N.H. REV. STAT. ANN. § 162-H:1, (2009); VT. STAT. ANN. tit. 30, § 202a(1) (2008).

C. FERC's Treatment Of Installed Capacity Requirements

FERC has espoused a variety of positions on its jurisdiction to set electric reserve or capacity requirements. For example, in 2002, FERC proposed to create a regional "resource adequacy requirement to provide for sufficient supply and demand resources to avert [resource] shortages." *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 100 FERC ¶ 61,138 (2002) at P 459, 67 Fed. Reg. 55,452, 55,511 (Aug. 29, 2002). Relying on its "broad" authority to

remedy undue discrimination and anticompetitive effects, FERC proposed to require that each regional system operator "forecast the future demand for its [geographic] area, facilitate determination of an adequate level of future regional resources by a Regional State Advisory Committee, and assign each [public utility] in its area a share of the needed future resources based on the ratio of its load to the regional load." *Id.* at PP 101, 474. This proposal was modeled after "the traditional reserve margin requirement imposed by states on monopoly utilities" and was "designed to complement, not replace, existing state resource adequacy programs." *Id.* at PP 480-81.

This proposal drew concerns that it would "infringe on state jurisdiction," and in response, FERC issued a "White Paper" "indicat[ing] that . . . nothing in the Final Rule would change state authority over resource adequacy requirements . . . ." *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 112 FERC ¶ 61,073 (2005) at PP 3-4, 70 Fed. Reg. 43,140, 43,141 (July 26, 2005). Despite these assurances, the States' doubts persisted, and FERC terminated the rulemaking without a final rule. *Id.* at P 7. In contemporaneous proceedings, States continued to insist that "the Resource Adequacy issue is wholly outside of the Commission's purview" and that "the Commission has no authority over adequacy of generation." *Midwest Indep. Transmission Sys. Operator, Inc.*, 103 FERC ¶ 61,210

(2003) at P 17. In response, FERC "agree[d] . . . that resource adequacy programs, in particular, are the responsibility of the states." *Id.* at P 21.

Notwithstanding this agreement that resource adequacy programs are States' responsibility, in New England, FERC has asserted plenary jurisdiction to dictate the amount of capacity resources that public utilities in each State must provide. In April 2003, FERC first ordered the New England system operator "to make a timely [FPA] Section 205 filing of" Objective Capability values, an earlier term for ICR. *NSTAR Elec. & Gas Corp. v. New England Power Pool*, 103 FERC ¶ 61,093 (2003) at P 23. In 2005, at the inception of this case, FERC took a step further, asserting its "authority to accept" the proposed ICR, making its own assessment of the proper amount of required capacity, rejecting Connecticut's objections, and increasing or decreasing the level of required capacity reserves based on its own judgments. *ISO New England Inc.*, 112 FERC ¶ 61,254 (2005).

D. Installed Capacity Requirements And The Forward Capacity Market

In New England, "[t]he purpose of calculating the ICR . . . is to determine the amount of resources that need to be procured in the [Forward Capacity Market] in order to meet the resource-adequacy reliability criterion." JA 58. The regional system operator files "the Installed Capacity Requirements and Local Sourcing Requirements for each upcoming

Power Year . . . with [FERC] pursuant to Section 205 of the [FPA]." JA 29. ICR is an "exogenously-determined" "input" into the Forward Capacity Auction mechanism. *Me. Pub. Utils. Comm'n*, 520 F.3d at 480. Through this auction, each public utility "must provide" its allotted megawatt share of the ICR. *See supra* at 9.

III. PROCEEDINGS BELOW

A. Proceedings Before FERC

FERC initially asserted its "authority to accept [the] proposed [ICR]" because it was "simply determining the [ICR], as the [Independent System Operator] Tariff and the New England Participants Agreement provide." *ISO New England Inc.*, 112 FERC ¶ 61,254 at P 17. The U.S. Court of Appeals for the D.C. Circuit found this rationale wanting and remanded to FERC for further proceedings, relying on *SEC v. Chenery Corp.*, 318 U.S. 80 (1942). *Conn. Dep't of Pub. Util. Control v. FERC*, 484 F.3d 558 (D.C. Cir. 2007) ("*Conn. Dep't I*"). In two subsequent proceedings and on remand of the first proceeding, FERC declared its jurisdiction based on FPA Section 205, 16 U.S.C. § 824d(a), contending that setting ICR was a practice "affecting" transmission and wholesale power sales rates and charges, thereby conferring on itself authority to set ICR, notwithstanding the FPA's declaration that FERC "shall not have jurisdiction" over generation facilities or resource adequacy determinations. Pet. App. 31-32, 147-48, 204. Connecticut submitted timely rehearing requests, which FERC

denied on the same grounds. Pet. App. 105-06, 182-83, 215.

B. Proceedings In The Court Of Appeals

Within 60 days of each rehearing order, Connecticut filed petitions with the Court of Appeals for the D.C. Circuit for review of FERC's orders, as required by FPA Section 313(b), 16 U.S.C. § 825*l*(b). The Court of Appeals consolidated those three proceedings. On June 23, 2009, without fully analyzing the FPA's unambiguous text preserving the States' jurisdiction, the Court of Appeals deferred to FERC's interpretation of the phrase "practices affecting . . . rates" as conferring authority to set the ICR, denied the petitions, and entered judgment. Pet. App. 18-19. The Court of Appeals "afford[ed] *Chevron* deference to the Commission's assertion of jurisdiction." *Id.* at 9 (citing *Chevron U.S.A. Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984)).

In affirming FERC's authority to set ICR, the Court of Appeals first acknowledged that "a higher ICR may . . . feel like an imperative," but nevertheless concluded that it did not "directly compel[ ] construction of new generation facilities." *Id.* at 13. Second, the Court of Appeals found "nothing in the Federal Power Act [that] expressly proscribes requiring [public utilities] to pay for a certain amount of capacity," and dismissed as irrelevant those provisions – Sections 207 and 215(i)(2)-(3) – that directly prohibit the exercise of federal jurisdiction over

resource adequacy. *Id.* at 13-14. Third, the Court of Appeals accepted FERC's interpretation of ICR as a practice affecting rates, placing it "within the heartland of the Commission's section 206 jurisdiction, *see* § 824e(a)."[2] *Id.* at 15. Fourth, the Court of Appeals found that its precedents establishing FERC's jurisdiction to set the amount of capacity "charge[s]" or to allocate the costs of capacity among corporate affiliates were indistinguishable from FERC's authority to set the amount of electric facilities or capacity (measured in megawatts) that each public utility in a State must provide. *Id.* at 15-17.

On July 14, 2009, Connecticut petitioned for panel rehearing or rehearing *en banc*. On July 28, 2009, the Court of Appeals denied those petitions.

REASONS FOR GRANTING THE PETITION

The Court of Appeals' judgment upsets the clear-cut balance that Congress struck when it apportioned jurisdiction for electric regulation between FERC and the States. The FPA plainly states that FERC "shall not have jurisdiction" over electricity production facilities, it "shall have no authority to compel the enlargement of generating facilities" in the name of adequate or sufficient service to be furnished, and it may not "preempt any authority of any State to take

[2] *See supra* note 1 at 5-6.

action to ensure the . . . adequacy, and reliability of electric service within that State." 16 U.S.C. §§ 824(b)(1), 824f, 824o(i)(3). By deferring to FERC's criterion for accreting authority – *i.e.*, whether a practice "affects" jurisdictional rates – the Court of Appeals departs from the no-deference rule of some of its sister circuits and disregards the governing statute, thereby permitting FERC to expand its powers exponentially into realms that Congress made clear it did not intend. When FERC mandates capacity requirements, in the form of ICR, it usurps the States' traditional responsibility to determine the need for electric capacity and thereby disrupts the federalism principles that guided Congress when it enacted and later amended the FPA. This Court should grant the requested writ to preclude FERC's assertion of jurisdiction over regulatory decisions that the FPA, by its plain text, expressly reserved to the States.

First, the lower courts urgently require the Court's direction on the fundamental applicability of *Chevron* to an agency's interpretation of its own powers when Congress has expressly and unambiguously partitioned State and federal responsibility along a bright line. States challenging FERC's jurisdiction in the Court of Appeals for the D.C. Circuit, as in this case – or in the Third, Fourth, and Ninth Circuits, where a similar rule may prevail – must overcome the court's usually dispositive deference to the agency's determination of its own jurisdiction, while petitioners in the Seventh or

Second Circuits may face no such hurdle. *See infra* at 24-25. Scholars, as well, can decipher no reliable answer from this Court's decisions. *See* Nathan A. Sales and Jonathan H. Adler, *The Rest Is Silence: Chevron Deference, Agency Jurisdiction, and Statutory Silences*, 2009 U. ILL. L. REV. 102 (forthcoming, 2009), *available at* http://law.case.edu/faculty/adler_jonathan/articles/Silence-proof.pdf. Consequently, lower courts are left adrift, reaching different conclusions from circuit to circuit and sometimes from panel to panel within a circuit. The dueling rules create an intolerable uncertainty that must be resolved.

This case presents the issue starkly. The FPA by equal measures confers jurisdiction on FERC and precludes a federal assumption of the States' traditional regulatory role. By dictating the number of megawatts of installed electric production capability that public utilities in each State "need" and "must provide," FERC extends its own jurisdiction – and strips away State jurisdiction – based on its aggrandizing construction of the statute. In these circumstances, deference to the agency is tantamount to an abdication of judicial oversight to enforce the FPA's Congressionally-imposed constraints on the reach of federal regulation.

By deferring to FERC's extravagant reading of its FPA-constrained jurisdiction, the Court of Appeals' judgment conflicts with the rule in other circuits and this Court's precedents. Whether analyzed (1) as Congress' refusal to delegate interpretive authority to FERC over jurisdictional decisions, (2) under the

familiar "plain language" rubric of *Chevron* step one, *Chevron*, 467 U.S. at 842-43, or (3) as a Congressionally prohibited intrusion on traditional state powers, FERC's rendering of the statute is unjustifiable and should carry no weight. The Court of Appeals erred by deferring to FERC's ungrounded interpretation of its own jurisdiction, and this Court should grant the writ to provide essential guidance by resolving the split on this question among the Courts of Appeals and the conflicts between this Court's precedent and the Court of Appeals for the D.C. Circuit.

Second, Congress did not intend for Section 205 to confer open-ended federal authority over "practices affecting . . . rates," thereby nullifying the carefully drawn protections against infringement of States' traditional powers. This Court has cautioned against construing such an amorphous phrase so that it swallows up the express statutory limits on FERC's jurisdiction. *See, e.g.*, *Nw. Cent. Pipeline Corp. v. State Corp. Comm'n of Kan.*, 489 U.S. 493, 514 (1989); *Conway*, 426 U.S. at 280-82; *FPC v. Panhandle E. Pipe Line Co.*, 337 U.S. 498, 507-08 (1949); *infra* at 33-34. FERC's ungrounded reading of its powers over "practices affecting . . . rates" to encompass setting the amount of required capacity would rewrite the FPA, conferring on itself substantial new authority over areas traditionally reserved to the States and that Congress unambiguously placed off limits. Rather than respecting the bright line between the federal and State domains that Congress designed, by deferring to FERC's unsubstantiated interpretation of

its own jurisdiction, the Court of Appeals has created an indeterminate boundary between federal and State jurisdiction that must be revisited in each case, always deferring to the agency's self-interested view of whether a "practice" affects rates. This Court should grant Connecticut's petition to assess the validity and implications of such a radical new rule.

Finally, this case threatens critical State initiatives to develop cost-effective generation facilities and other resource adequacy measures that meet local needs and satisfy reliability requirements. Congress left regulation of electricity production with the States because they are best able to address local health, public safety, and welfare concerns and needs. States have taken the lead in setting objectives to lower greenhouse gas emissions, facilitating development of new nuclear resources, displacing fossil-fueled generation with "clean" coal, wind, and solar facilities, reducing demand, and using energy more efficiently. By assuming the right to dictate the amount of required generation in a State – including, for instance, determinations about how to assign a capacity "value" to intermittently operating wind or solar generation facilities and how much peak electric demand will grow – FERC will stifle those State-sponsored innovations. The extraordinarily adverse effects on federalism from FERC's judicially sanctioned misappropriation of administrative power warrant granting the writ.

I. The Court Of Appeals' Decision Conflicts With This Court's Guidance And The Rule In Other Circuits For Deference To An Agency's Interpretation Of Its Statutory Jurisdiction.

A. The Court Of Appeals Improperly Deferred To FERC's View Of The Division Between State And Federal Jurisdiction When Congress Did Not Delegate Such Interpretative Authority To The Agency.

The premise for *Chevron* deference derives, at least in part, from the proposition that Congress intended to delegate authority to the administrative agency to interpret ambiguous statutory terms. *See, e.g.*, *United States v. Mead Corp.*, 533 U.S. 218, 226-27 (2001) (holding "that administrative implementation of a particular statutory provision qualifies for *Chevron* deference when it appears that Congress delegated authority to the agency generally to make rules carrying the force of law"); *see also* Stephen Breyer, *Judicial Review of Questions of Law and Policy*, 38 ADMIN. L. REV. 363, 369-70 (1986) ("courts have used 'legislative intent to delegate the law-interpretive function' as a kind of legal fiction"); Clark Byse, *Judicial Review of Administrative Interpretation of Statutes: An Analysis of Chevron's Step Two*, 2 ADMIN. L.J. 255, 261 (1988) ("the vital pre-condition for this conclusion [to defer to the agency's interpretation] is the court's determination that the agency has been delegated the power to define the

statute"). If Congress made clear in the statute that it never intended for the agency to define the bounds of its own authority, courts have no basis for granting *Chevron* deference. *See Miss. Power & Light Co. v. Mississippi*, 487 U.S. 354, 386 (1988) (Brennan, J., dissenting) (courts should not defer to an agency's interpretation of a statute that "is designed to confine the scope of the agency's jurisdiction to the areas Congress intended it to occupy"); *Social Sec. Bd. v. Nierotko*, 327 U.S. 358, 369 (1946) (when Congress did not delegate authority, "[a]n agency may not finally decide the limits of its statutory power" because "[t]hat is a judicial function").

Congress intended to fix in the FPA a "clear and complete" line between State and federal jurisdiction that would "cut sharply and cleanly between" their respective spheres, thus obviating the need for case-by-case determinations. *S. Cal. Edison*, 376 U.S. at 214-15 (quoting *Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n*, 332 U.S. 507, 517 (1947)). As in *New York v. FERC*, 535 U.S. at 23, "the statutory text [is] the clearest guidance," and it circumscribes the respective realms of responsibility without equivocation – FERC "shall have jurisdiction," and it "shall not have jurisdiction." Congress intended for the FPA to provide a definitive apportionment of federal and State powers that would not require administrative interpretation, but to the extent that it did not make that decision clear, the courts properly resolve any jurisdictional dispute, without deference to the agency. Antonin Scalia, *Judicial Deference to Administrative*

Interpretations of Law, 1989 DUKE L.J. 511, 516 (1989). Moreover, the FPA was designed to confine federal jurisdiction while preserving the States' traditional powers, making it incongruous for the federal agency to decide the reach of its own authority.

The Court of Appeals here reflexively invoked *Chevron* deference to FERC's interpretation of its own jurisdiction without examining the threshold question – whether Congress intended to give this agency's view such primacy. Pet. App. 9. For the past 15 years, the Court of Appeals for the D.C. Circuit has consistently reviewed an agency's interpretation of its own jurisdiction "with the familiar *Chevron* framework in mind." *Okla. Natural Gas Co. v. FERC*, 28 F.2d 1281, 1283-84 (D.C. Cir. 1994); *but see ACLU v. FCC*, 823 F.2d 1554, 1567 n.32 (D.C. Cir. 1987) (concluding that it was "highly unlikely that a responsible Congress would implicitly delegate to an agency the power to define the scope of its own power"); *Otis Elevator Co. v. Sec'y of Labor*, 921 F.2d 1285, 1288 (D.C. Cir. 1990) (Thomas, J.) (considering the deference issue "unsettled"). Other circuits have held, however, that *Chevron* deference does *not* apply to an agency's determination of its own jurisdiction. *E.g.*, *N. Ill. Steel Supply Co. v. Sec'y of Labor*, 294 F.3d 844, 846-47 (7th Cir. 2002); *Bolton v. Merit Sys. Prot. Bd.*, 154 F.3d 1313, 1316 (Fed. Cir. 1998); *Natural Res. Def. Council v. Abraham*, 355 F.3d 179, 199 (2d Cir. 2004) (Oakes, J., Sotomayor, J.); *but see Snell Island SNF LLC v. NLRB*, 568 F.3d 410, 415

(2d Cir. 2009) (applying *Chevron* deference where "the question presented involves an agency's jurisdiction or power to act"). Some other circuits apparently share the D.C. Circuit's current view, although sometimes with reservations and material variations. *See, e.g., Air Courier Conference of Am./Int'l Comm. v. U.S. Postal Serv.*, 959 F.2d 1213, 1223 (3d Cir. 1992) (deferring to agency interpretation of its own jurisdiction), *but see id.* at 1225-26 (Becker, J., concurring) (noting that the court's holding does not require deference, reading the precedents differently, and describing a "more limited" deference on jurisdictional questions); *Saipan Stevedore Co. Inc. v. Dir., Office of Workers' Comp. Programs*, 133 F.3d 717, 723 (9th Cir. 1998) (giving agency's interpretation of the statute's jurisdictional reach "some weight" but only if the interpretation implicates the agency's "special competence"); *EEOC v. Seafarers Int'l Union*, 394 F.3d 197, 201 (4th Cir. 2005) (applying *Chevron* to an agency's interpretation of the bounds of its power because the Supreme Court has never held that *Chevron* should not apply). This Court has not decided the issue. *See* Sales & Adler, 2009 U. ILL. L. REV. at 104. The lower courts require further guidance that granting certiorari in this case will provide.

B. The Court Of Appeals' Decision Disregarded Clear Statutory Limitations On Federal Jurisdiction.

Even if Congress had intended for FERC to interpret ambiguous terms to expand its own jurisdiction, the agency is still bound by the unambiguous language of the FPA, and the plain text of the operative jurisdictional provision is clear: The Commission "shall have jurisdiction" over transmission in interstate commerce and the sale of electric energy at wholesale, "but *shall not have jurisdiction*, except as specifically provided . . . , over facilities used for the generation of electric energy . . . ." 16 U.S.C. § 824(b)(1) (emphasis added). True to this bright-line distinction between federal and State powers, the remainder of the statute specifies unmistakably those exceptional, "specifically provided" circumstances when FERC may exercise jurisdiction over generation facilities. *Id.* §§ 824a(c), 824b(a), 825(a), 825b; *supra* at 4-5. Lest there be any doubt, Congress reiterated its proscription on FERC's authority to order additional generation facilities in order to assure adequate, sufficient, or reliable electric service. *Id.* §§ 824f, 824o(i)(2)-(3). By linking generation facilities in this way with adequate, sufficient, or reliable electric service, Congress unambiguously reserved "generation . . . capacity" determinations for the States. This respect for States' traditional prerogative to determine the amount of "adequate" electricity production resources permeates the FPA.

The text of the statute alone should have ended the analysis. Under *Chevron* step one, "[f]irst, always, is the question whether Congress has spoken to the precise question at issue. If the intent of Congress is clear, that is the end of the matter; for the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." *Chevron*, 467 U.S. at 842-43; *see Barnhart v. Sigmon Coal Co., Inc.*, 534 U.S. 438, 462 (2002) (concluding that "[i]n the context of an unambiguous statute, we need not contemplate deferring to the agency's interpretation"). The Court of Appeals bypassed this essential first step, skipping directly to the supposed "ambiguity" introduced by the phrase "practices . . . affecting . . . rates" in Section 206, 16 U.S.C. § 824e(a).[3] Seizing on the mantra that "[w]e afford *Chevron* deference to the Commission's assertions of jurisdiction," Pet. App. 9, the Court of Appeals never examined Congress' intent, as revealed in the statute's plain language.

As it had in *Chevron*, this Court reiterated in *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000), that Congress' clearly expressed intent – reflected in the statute when examined as a whole – controls any determination of an agency's jurisdiction. After scrutinizing the "overall regulatory scheme," including subsequently enacted legislation, the Court found a "clear intent [that] the FDA's

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[3] *See supra* note 1 at 5-6.

assertion of jurisdiction is impermissible." *Id.* at 126. "[A] reviewing court should not confine itself to examining a particular statutory provision in isolation. The meaning – or ambiguity – of certain words or phrases may only become evident when placed in context." *Id.* at 132. Moreover, "the meaning of one statute may be affected by other Acts, particularly where Congress has spoken subsequently and more specifically to the topic at hand." *Id.* at 133.

Because it rushed to defer to the agency's view, the Court of Appeals never undertook this required examination of Congress' expressed intent. Instead of applying the precept that an agency "has no power to act . . . unless and until Congress confers power on it," *La. Pub. Serv. Comm'n v. FCC*, 476 U.S. 355, 374 (1986), the Court of Appeals looked only at whether the FPA "expressly proscribes requiring [public utilities] to pay for a certain amount of capacity." Pet. App. 13. It did not consider the overarching, bright line that the FPA struck between federal and State jurisdiction. It did not analyze the meaning of the phrase "specifically provided" in Section 201(b)(1), 16 U.S.C. § 824(b)(1), which delimits any exceptions to the strict prohibition on federal jurisdiction over generation facilities. *See infra* at 34-35. It did not evaluate the import of the 2005 amendments in Section 215(i), 16 U.S.C. § 824o(i), to shed light on Congress' intention to place resource adequacy determinations entirely off limits for FERC. *See infra* at 30-31. It dismissed the explicit prohibitions on FERC powers to compel the enlargement of

generation facilities to achieve "adequate" service in Section 207, 16 U.S.C. § 824f, as applying only to "*energy*," Pet. App. 14 (emphasis added), without considering the fact that FERC's *only* jurisdictional grant applies solely to "energy," and not to "capacity." *See* 16 U.S.C. § 824(b)(1). In sum, the Court of Appeals short-circuited *Chevron's* essential first step. If left undisturbed, the result will mean a fundamental transfer to FERC of jurisdiction over traditional State responsibilities for determining the amount of needed capacity, effectuated through administrative fiat and contrary to Congress' clearly expressed intent. The Court should grant certiorari to decide whether this power transfer from States to federal administrators is inconsistent with the plain text of the FPA.

C. Contrary To This Court's Recent Holdings, The Court Of Appeals' Construction Of The FPA Gave Insufficient Weight To The Preservation Of Traditional State Powers.

The FPA does not confer interpretative authority on FERC to construe its own statutory jurisdiction vis-a-vis the States' traditional authority. Even "the presence of some uncertainty" on this point, however, would "not expand *Chevron* deference to cover virtually any interpretation" of the FPA so long as it is possible to "discern the outer limits" of any potentially ambiguous terms. *Cuomo v. Clearing House Ass'n*, 129 S. Ct. 2710, 2715 (2009). Evidence from the time

of the statute's enactment, the Court's prior cases, and application of the normal principles of statutory construction to the FPA may define those outer limits. *See id.* As in *Clearing House*, it is unnecessary to invoke a presumption against pre-emption in "giving force to the plain terms of the" FPA, but FERC's incursion "upon traditional state powers" still should not be minimized. *Id.* at 2720; *see Rapanos v. U.S. Army Corps of Eng'rs*, 547 U.S. 715, 738 (2006) ("[w]e ordinarily expect a 'clear and manifest' statement from Congress to authorize an unprecedented intrusion into traditional state authority"). Congress did not intend for FERC to intrude on the States' traditional responsibility for determining the amount of electrical production facilities that will be adequate or sufficient.

The text of the FPA itself refutes any supposed Congressional intention that FERC assume the States' role in regulating generation facilities or the need for electric production. Sections 201(b)(1), 202(b), and 207 each preclude FERC authority to compel the enlargement of generation facilities to assure adequate or sufficient service. 16 U.S.C. §§ 824(b)(1), 824a(b), 824f; *supra* at 2-4. Congress spoke most recently in the Energy Policy Act of 2005, when it added Section 215 but expressly prohibited FERC from setting or enforcing standards for the adequacy of generation facilities or ordering "additional generation . . . capacity" and preserved State authority "to take action to ensure the . . . adequacy, and reliability of electric service within

that State . . . ." 16 U.S.C. § 824o(i)(2)-(3). Congress would not have taken these categorical steps in 2005 to confine FERC's powers if it had actually intended for FERC to assume precisely those same powers through its expansive reading of the statute.

This Court and FERC have acknowledged States' traditional hegemony "in the regulation of electricity production," "regulating electrical utilities for determining questions of need," determining the "[n]eed for new power facilities," "plant-need questions," "the need for additional generating capacity," and "regulation of most power production." *Pac. Gas & Elec.*, 461 U.S. at 194, 205, 208, 212; *New York v. FERC*, 535 U.S. at 12 n.9. Virtually every State has statutes like Connecticut and the other New England States requiring State regulators to conduct long-term planning to assure adequate capacity resources to meet projected needs. *Supra* at 11-12. Nothing in the FPA displaced that traditional authority, and FERC may not do so by administrative decree. The Court should grant Connecticut's petition to address this crucial question of federalism.

II. The Court Of Appeals' Decision Granting FERC Jurisdiction To Set ICR As A "Practice Affecting . . . Rates" Conflicts With This Court's Precedent And With The FPA's Unambiguous Reservation Of Jurisdiction To The States.

A. This Court Has Rejected The Court Of Appeals' Expansive And Improper Interpretation Of "Practices Affecting . . . Rates" To Grant Jurisdiction That The FPA Otherwise Prohibits.

Even if there were some ambiguity in the FPA's prohibitions on FERC jurisdiction to dictate the amount of capacity resources that States must provide, FERC seeks to transform clear statutory constraints into broad bureaucratic discretion, and its groundless interpretations are unreasonable, unpersuasive, and do not merit deference. FERC – now with the Court of Appeals' sanction – construes the "practices . . . affecting" rates language in Section 205 as condoning its appropriation of jurisdiction over the sufficiency of generation facilities, notwithstanding the statute's explicit bar on FERC orders that set adequacy standards for State-regulated electricity production facilities. *See* Pet. App. 15. This Court has never given such sweeping import to that common phrase. Indeed, applying the canon of construction *noscitur a sociis*, *see Gustafson v. Alloyd Co.*, 513 U.S. 561, 575 (1995) ("a word is known by the company it keeps"), "practices" should be interpreted consistently with the series to which it

belongs – "classifications, practices, and regulations affecting . . . rates and charges, together with all contracts which in any manner affect or relate to such rates . . . ," 16 U.S.C. § 824d(c) – not as authorizing a sea change in federal jurisdiction at the expense of the States' historical powers. This Court has never endorsed such a leap.

For instance, in *Northwest Central*, the Court, interpreting comparable language in the Natural Gas Act ("NGA"), 15 U.S.C. § 717c(a), (c), concluded that

> [t]o find field pre-emption of [a State's] regulation [of production facilities] merely because purchasers' costs and hence rates might be affected would be largely to nullify that part of NGA § 1(b) [15 U.S.C. § 717(b)] that leaves to the States control over production for there can be little if any regulation of production that might not have at least an incremental effect on the costs of purchasers in some market and contractual situations. Congress has drawn a brighter line, and one considerably more favorable to the States' retention of their traditional powers to regulate rates of production . . . .

Northwest Central, 489 U.S. at 514; *see also FPC v. Panhandle*, 337 U.S. at 513-14 ("we should not by an extravagant, even if abstractly possible, mode of interpretation push powers granted over transportation and rates so as to include production").

As this Court made clear in *Conway*, Sections 205 and 206 do not provide an independent basis for jurisdiction at all. In that case, the Federal Power Commission refused to consider the potential discriminatory or anticompetitive effects of retail electric rates on proposed wholesale rates because Section 201(b)(1) excludes retail rates from federal jurisdiction in the same way that it excludes generation facilities. *Conway*, 426 U.S. at 276-77. The Court held that the phrase "subject to the jurisdiction of the Commission" in Sections 205 and 206 "necessarily implicate[s]" a jurisdictional sale under Section 201(b)(1) and, therefore, does not supplant express exclusions from federal jurisdiction. *Id.* While the Commission may "consider" the effects of retail rates in setting jurisdictional wholesale rates and may adjust the wholesale rates accordingly, it may not order changes to non-jurisdictional retail rates. *Id.* at 279-80. The same analysis applies here to permit FERC to "consider" ICR in setting wholesale capacity charges, but FERC may not set the amount of production facilities States must provide, even assuming that this amount is a "practice affecting" wholesale rates.

Moreover, the nebulous reference to "practices" in Section 205 does not "specifically provide" for FERC jurisdiction over the need for generation facilities, as would be required if it were to fit within the exception in Section 201(b)(1). "Specifically," as understood in 1935, means "[w]ith exactness and precision; in a

definite manner" or "precisely formulated or restricted; specifying; definite, or making definite; explicit; of an exact or particular nature; as, a *specific* statement." *See* WEBSTER'S NEW INTERNATIONAL DICTIONARY OF THE ENGLISH LANGUAGE 2414-15 (2d ed. 1934) (emphasis in original). The FPA contains several examples of such "specific provision" for federal jurisdiction over generation facilities. *Supra* at 4-5. "Practices affecting" rates, however, is not a definite, explicit, exact, or precise reference to generation facilities and may not support FERC's administrative appropriation of reserved State authority. *See MCI Telecomms. Corp. v. AT&T*, 512 U.S. 218, 231 (1994) (finding it "highly unlikely" that Congress would change the essential characteristics of a rate-regulated industry "through such a subtle device as permission to 'modify' rate filing requirements"); *Whitman v. Am. Trucking Ass'ns, Inc.*, 531 U.S. 457, 468 (2001) (holding that "Congress . . . does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions – it does not, one might say, hide elephants in mouseholes"). Indeed, to the extent that "practices affecting . . . rates" is ambiguous, requiring FERC's interpretative gloss to derive meaning, it could not be a "specific provision" sufficient to override the Congressional prohibition on jurisdiction over generation facilities. The Court should grant certiorari to clarify the limits on FERC's assumption of authority over "practices affecting . . . rates" to commandeer the States' reserved responsibilities.

B. The Court Of Appeals' Interpretation Of "Practices Affecting ... Rates" As A Basis For Jurisdiction Would Require A Case-By-Case Determination Of FERC's Authority And Risks An Unbounded Expansion Of Federal Powers.

The Court of Appeals' "practices affecting ... rates" jurisdictional test creates an untenable conundrum. If unchecked, the Court of Appeals' logic leaves FERC free to assert far-reaching authority to control any conduct that impacts wholesale electric rates, regardless of whether those areas have traditionally been regulated by the States and are, therefore, protected by Congress in the FPA's plain language. The revolutionary extent of this new paradigm is breathtaking. As this Court warned 60 years ago when construing comparable language in the NGA, "[t]o accept these arguments springing from power to allow interstate service [and] fix rates ... would establish wide control by the Federal Power Commission over the production [of electricity]. It would invite expansion of power into other phases of the forbidden area." *FPC v. Panhandle*, 337 U.S. at 509.

Indeed, FERC has already seized on the opening that the Court of Appeals afforded, asserting its jurisdiction – despite States' objections – to require rules for aggregators of retail customers to bid demand response directly into wholesale electric energy markets, thereby compelling States to adopt laws and regulations on end-use customer aggregation

and thereby usurping State regulation of retail customers. *Wholesale Competition in Regions with Organized Electric Markets*, 128 FERC ¶ 61,059 (2009) at P 45 n.67, 74 Fed. Reg. 37,776, 37,782 (July 29, 2009), citing Pet. App. 16-19. The factors that "affect" the costs of electricity production and, therefore, wholesale rates are legion, many with a much more direct and consequential impact than the ICR – *e.g.*, State emission control rules that specify smokestack scrubbers and other expensive equipment, zoning ordinances that dictate the location of new generation at more costly sites, or worker safety regulations that increase the costs of constructing and operating generation facilities. If "practices affecting . . . rates" is the test, FERC's expansive construction of its jurisdictional umbrella may soon cover all of those "practices," contrary to Congress' expressed intent in the FPA's plain language.

The only alternative to prevent runaway FERC power would be a case-by-case determination of whether a particular "practice affecting . . . rates" is within the FPA's Section 205 penumbra. This approach fails on two counts. First, the Court of Appeals' only suggestion of some constraint is its reference to FERC's declaration that "ICRs have a *significant and direct* effect on jurisdictional rates . . . ." Pet. App. 8 (emphasis added). This is no constraint at all, particularly when FERC determines whether a practice is sufficiently "significant and direct," and its judgments may command *Chevron* deference. Second, Congress adopted a bright-line

jurisdictional test precisely to avoid such a case-by-case approach. *See S. Cal. Edison*, 376 U.S. at 215-16. The Court of Appeals' test will invite endless litigation to discern the exact boundary of FERC's new jurisdiction. This Court should grant the petition to consider the validity and viability of a jurisdictional standard derived only from the "practices affecting . . . rates" provision in Sections 205 and 206.

III. The Court Of Appeals' Decision Raises An Issue Of Exceptional Importance Because It Threatens The States' Ability To Control Electricity Production Facilities Within Their Borders And Thereby To Protect Their Citizens' Health, Public Safety, And Welfare.

States have a vital interest in assuring sufficient electric production facilities to provide adequate service. Local police and fire departments, hospitals, schools, manufacturers, retailers, and governments could not function effectively without a secure, reasonably uninterrupted flow of electric energy. Few commodities are more essential for a community's health, public safety, and welfare than electricity. No State official could remain in office if she or he permitted the State's electric production resources to fall below the levels necessary for and demanded by its citizens.

The difficulty comes in deciding how many of those resources will be just "enough," but not too much. No commercial-scale, practical technology

exists to store electricity. Thus, an accessible generation facility must be available and running to meet the demand at any moment. Of course, generation facilities that provide capacity but that may only be called into use on a rare, sweltering August afternoon add substantially to the costs of electricity even though they produce very little energy. While curtailing electric consumption when demand is greatest may be an option for some retail customers, most users cannot or will not tolerate such service interruptions or may lack the technology to reduce usage whenever the regional system operator requests. State regulators, who are directly accountable to their constituents, must weigh the very local interests of maintaining the right amount of generation capacity to assure reasonable reliability but not so much that the costs become unacceptable. State regulators must also weigh the "need and necessity" for generation facilities at particular sites that may face intensive community opposition. Finally, States have implemented emission control programs that often dictate the number and technology of acceptable generation facilities. Not surprisingly, Congress recognized all of these particularly local interests and in the FPA, broadly reserved to the States control over electricity production.

By mandating the amount of capacity that States "must provide," as it does in setting ICR, FERC assumes a role that Congress did not intend and that usurps the States' legitimate needs to regulate electricity production in its citizens' best interests.

This case raises a federalism issue of the first order and, therefore, warrants this Court's attention.

CONCLUSION

The Court should grant the writ of certiorari to determine the deference owed to FERC, if any, when it interprets the statutory boundary between federal and State jurisdiction in a Congressionally dictated dual regulatory system. The Court should also grant the petition to decide whether the phrase "practices affecting . . . rates" permits FERC to mandate the amount of electric capacity resources that each State must provide.

Respectfully submitted,

RANDALL L. SPECK
Counsel of Record
KIMBERLY B. FRANK
LISA B. KATZ
REBECCA E. GRUNFELD
KAYE SCHOLER LLP
901 15th Street, NW
Washington, DC 20005
Telephone: (202) 682-3510
Facsimile: (202) 682-3580
Counsel for Petitioner
Connecticut Department
of Public Utility Control

JOHN S. WRIGHT
MICHAEL C. WERTHEIMER
Assistant Attorneys General
OFFICE OF THE
ATTORNEY GENERAL
10 Franklin Square
New Britain, CT 06051
Telephone: (860) 827-2684
Facsimile: (860) 827-2893
Counsel for Petitioner
Richard Blumenthal,
Attorney General for the
State of Connecticut

Dated: September 3, 2009

APPENDIX A

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued May 12, 2009 Decided June 23, 2009

No. 07-1375

CONNECTICUT DEPARTMENT OF PUBLIC UTILITY CONTROL,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

NEW ENGLAND POWER POOL
PARTICIPANTS COMMITTEE, ET AL.,
INTERVENORS

Consolidated with 07-1460, 08-1175

On Petitions for Review of Orders
of the Federal Energy Regulatory Commission

Randall L. Speck argued the cause and filed the briefs for petitioner.

John S. Wright and *Michael C. Wertheimer*, Assistant Attorneys General, Attorney General's Office of State of Connecticut, *Jesse S. Reyes*, Assistant Attorney General, Attorney General's Office of Commonwealth of Massachusetts, and *Lisa C. Fink* were on the briefs for intervenors Richard

Blumenthal, Attorney General for the State of Connecticut, Maine Public Utilities Commission, and Massachusetts Department of Public Utilities in support of petitioner. *Lisa S. Gast* entered an appearance.

James Bradford Ramsay, William H. Smith, Jr., Frank R. Lindh, Mary F. McKenzie, Christopher E. Clay, Michael A. Cox, Attorney General, Attorney General's Office of State of Michigan, *Steven D. Hughey, Michael A. Nickerson*, and *Patricia S. Barone*, Assistant Attorneys General, *David D'Alessandro, Harvey L. Reiter, Anne Milgram*, Attorney General, Attorney General's Office of State of New Jersey, *Margaret Comes*, Deputy Attorney General, *Jonathan D. Feinberg, Gisele L. Rankin, John A. Levin*, and *Florence P. Belser* were on the brief of *amici curiae* National Association of Regulatory Utility Commissioners et al. in support of petitioner. *Grace D. Reyes* and *Caroline Vachier*, Assistant Attorney General, Attorney General's Office of State of New Jersey, entered appearances.

Nancy H. Rogers, Attorney General, Attorney General's Office of State of Ohio, and *Duane W. Luckey* and *Thomas W. McNamee*, Assistant Attorneys General, were on the brief for *amicus curiae* State of Ohio in support of petitioner.

Samuel Soopper, Attorney, Federal Energy Regulatory Commission, argued the cause for respondent. With him on the brief were *Cynthia A. Marlette*, General Counsel, and *Robert H. Solomon*, Solicitor.

John N. Estes III argued the cause for intervenors New England Power Pool Participants Committee, et al. With him on the brief were *Scott Phillip Myers, Paul Franklin Wight, James C. Beh, Shay Dvoretzky, Larry F. Eisenstat, George E. Johnson,* and *Christopher C. O'Hara.*

Sherry A. Quirk and *Montina M. Cole* were on the brief for intervenor ISO New England, Inc. in support of respondent.

Barry S. Spector and *Paul M. Flynn* were on the brief of *amicus curiae* PJM Interconnection, L.L.C. in support of respondent.

Ashley C. Parrish and *David G. Tewksbury* were on the brief for amicus curiae The Electric Power Supply Association in support of respondent.

Before: TATEL, GARLAND, and GRIFFITH, *Circuit Judges.*

Opinion for the Court filed by *Circuit Judge* TATEL.

TATEL, *Circuit Judge*: Today we address a question we have twice deferred: whether the Federal Energy Regulatory Commission has jurisdiction to review something called the Installed Capacity Requirement (ICR), a key input into the market-based mechanism that determines transmission tariffs and end-user costs in the New England bulk power system. The question is presented here by the Connecticut Department of Public Utility Control and allied intervenors, all petitioning for review of various

instances where the Commission has approved or modified the amount of the ICR. Although the details of this market mechanism are somewhat opaque and surely complicated, the ultimate legal issue before us reduces to a clear and simple one: does the Commission's review of the ICR constitute direct regulation of electrical generation facilities? If so, it exceeds the Commission's authority under the Federal Power Act; if not, it falls within the Commission's jurisdiction over practices affecting wholesale rates. Finding no direct regulation of electrical generation facilities in the Commission's review of the ICR, we deny the petitions for review.

I.

"Capacity" is not electricity itself but the ability to produce it when necessary. It amounts to a kind of call option that electricity transmitters purchase from parties – generally, generators – who can either produce more or consume less when required. The penultimate and most proximate buyers of capacity (before the consumers who ultimately shoulder the costs in their utility bills) are called "load serving entities" or LSEs – the public utilities that deliver electricity to end users. The goal is for LSEs to purchase sufficient capacity to easily meet expected peaks in electricity demand on their transmission systems.

Because local LSEs will experience demand peaks at different times, and because interconnected

LSEs can easily share excess capacity when necessary, these utilities can capture considerable efficiencies through cooperative decision making about how much capacity to buy as a whole and at what cost. *See generally Gainesville Utils. Dep't v. Fla. Power Corp.*, 402 U.S. 515, 518-20 & n.3 (1971) (explaining reserve capacity efficiencies from interconnection). Indeed, cooperation may be necessary to avoid a free rider problem, where some utilities count on the capacity they expect others to buy in order to support their own reliability. Accordingly New England has a history of cooperative decision making about capacity, dating back to the 1971 creation of the New England Power Pool (NEPOOL), the voluntary association of all New England public utilities that, subject to Commission review, set capacity requirements for each individual utility and administered "deficiency charges" for those that failed to obtain their share. *See Municipalities of Groton v. FERC*, 587 F.2d 1296, 1300-03 (D.C. Cir. 1978). That role has since shifted to ISO New England, Inc. (ISO-NE), a regional transmission organization that administers open access to transmission facilities in the New England bulk power system pursuant to the Commission's deregulatory mandate. *See Me. Pub. Utils. Comm'n v. FERC*, 520 F.3d 464, 467-68 & n.2 (D.C. Cir. 2008) (describing ISO-NE); *see generally Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000) (affirming Commission's open access transmission approach to fostering competition). Despite this cooperation, however, inefficiencies remained.

Lacking open market mechanisms for setting capacity prices and quantities, ISO-NE struggled to incentivize innovation and investment in the capacity market while simultaneously suppressing costs. In an initial effort to respond to concerns over short supply, ISO-NE entered into "Reliability Must-Run" agreements with older and less efficient generators, pursuant to which ISO-NE paid for their inefficiencies so as to keep them on line and ensure system reliability. But the Commission disfavors such agreements because they "'suppress market-clearing prices . . . and make it difficult for new generators to profitably enter the market.'" *Me. Pub. Utils. Comm'n*, 520 F.3d at 468 (quoting *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082, at 61,270 (2003)). Responding to these concerns, ISO-NE endeavored to create a different system with an "administratively-determined demand curve that would establish the price and quantity of capacity that must be procured" in the various sub-regions of the New England grid. *Id.* (internal quotation marks omitted). But this too ran into problems: it produced enormous controversy over the shape of the hypothetical curve. *Id.* at 468 & n.3 (criticizing the very concept of a "demand curve" constructed by a central decision maker). In short, these efforts failed to harness the power of competitive markets in determining the appropriate price of capacity, leading to inaccurate or inefficient levels of investment in or compensation for capacity providers.

Enter the Forward Capacity Market, which the Commission approved as part of a settlement agreement among New England power system stakeholders on June 16, 2006. *See id.* at 469. In the Forward Market – the details of which are at issue here – capacity providers bid for contracts three years in the future as part of a "descending clock auction." Here's how it works. ISO-NE determines the Installed Capacity Requirement, or ICR, which represents the estimated amount of capacity the system as a whole will require for reliability three years hence. It then announces the starting price – by agreement, twice the estimated cost of new entry – and capacity providers state an amount of capacity they would be willing to offer at that price. If these offerings exceed the ICR, ISO-NE lowers the offering price, which in turn lowers the quantity offered in response. This descending price clock "stops" when the quantity offered equals the ICR, and that price point becomes the market clearing price. The capacity charge for each utility in the system is thus its share of the ICR multiplied by the clearing price.

Bidders in the Forward Market include existing generators, new entrants who believe they can obtain the necessary state and municipal permits to construct new generation, and demand-side resources, including users who can produce their own power or reduce their demand during shortages. Their bids commit them to supply the amount they offer at the clearing price. By using competitive bidding for future capacity contracts, this system both

incentivizes and accounts for new entry by more efficient generators, while ensuring a price both adequate to support reliability and fair to consumers.

In *Maine Public Utilities Commission v. FERC*, we reviewed a broad settlement among the many parties involved in New England's bulk power system and rejected a challenge to the Commission's authority to create and review the operation of the Forward Market. 520 F.3d at 479-80. In so doing, however, we expressly reserved the question whether the Commission's review of the ICR created an independent jurisdictional problem, emphasizing that another pending case – this one – presented that very question. *Id.* at 480. When this issue was initially before us in 2007, we remanded to the Commission so that it could explain the statutory basis for its jurisdiction to review the ICR. *See Conn. Dep't of Pub. Util. Control v. FERC*, 474 F.3d 558, 560-61 (D.C. Cir. 2007). On remand, the Commission explained its view that "ISO-NE's ICRs have a significant and direct effect on jurisdictional rates and services, [and] therefore fall within the Commission's jurisdiction." *ISO New England, Inc.*, 122 F.E.R.C. ¶ 61,144, at 61,763 (2008). The case now returns to us for review, having been consolidated with other petitions presenting the same issue.

Notwithstanding our approval of the Forward Market in *Maine Public Utilities Commission*, petitioners argue that the Commission's authority to approve or modify the ICR as part of its review of ISO-NE's transmission tariffs exceeds its jurisdiction

under the Federal Power Act. In their view, any movement upward in the Installed Capacity Requirement requires installing capacity, and under section 201 of the Federal Power Act, the Commission "shall not have jurisdiction . . . over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). The Commission responds by emphasizing its broad power over practices affecting wholesale rates, *see* 16 U.S.C. § 824e(a), and by arguing that the effect of the ICR on new generation capacity is sufficiently incidental to avoid section 201's bar. We afford *Chevron* deference to the Commission's assertion of jurisdiction. *Okla. Natural Gas Co. v. FERC*, 28 F.3d 1281, 1283-84 (D.C. Cir. 1994); *see also Chevron U.S.A. v. Natural Res. Def. Council*, 467 U.S. 837, 842-43 (1984).

II.

A twin pair of concessions radically simplifies the legal question before us. Petitioners concede that the Commission may "determine[] just and reasonable capacity charges," Petrs.' Reply Br. 28, and that it may set those charges so as to incentivize the procurement or creation of additional capacity to ensure system reliability, *id.* at 28-29. For its part, the Commission concedes that while it has broad power over practices affecting ISO-NE's transmission tariffs, "Connecticut is obviously correct that the [Act] prohibit[s] the Commission from directly regulating generating facilities." Respt.'s Br. 22. Rephrased to fit the standard of review, these concessions leave only

one question: does setting the ICR represent the kind of direct regulation of generation facilities plainly forbidden by section 201? The answer is no. Our precedent is substantially on point, and we think the controversy stems in large part from the fact that the ICR is woefully misnamed.

The "Installed Capacity Requirement" is misnamed because increasing it doesn't actually "require" anyone to "install" any new "capacity" at all. State and municipal authorities retain the right to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally-friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission. Of course, those choices affect the pool of bidders in the Forward Market, which in turn affects the market clearing price for capacity. And in an extreme situation where local regulators utterly refused to allow creation of any new capacity to offset increases in the ICR, the price would rise towards the initial offering price of two times the cost of new entry. But this is all quite natural: if consumer-constituents of state commissions prefer to forbid the construction of new power plants, they will appropriately bear the costs of that decision, including paying more for system reliability from older and less efficient units. Thus, we think the ICR is better understood not as a capacity *requirement* but as something more like a peak demand estimate – perhaps, in FERC-speak, a PDE – and the

purpose of the Forward Market is only to locate the price at which market incentives will be sufficient to meet that expected demand. Because petitioners concede that ISO-NE and the Commission could directly set the price of capacity at this level precisely to incentivize procurement of resources adequate to meet their estimate of peak demand, *see* Petrs.' Reply Br. 28-29, and because this estimate necessarily affects prices but not necessarily new capacity construction, we see no direct regulation of generation facilities in violation of section 201.

This brings us to our precedent, which explains petitioners' seemingly surprising – but in fact unavoidable – concession. In *Municipalities of Groton v. FERC,* we sustained the Commission's jurisdiction to review the "deficiency charges" that NEPOOL charged as ISO-NE's predecessor when member utilities failed to live up to their share of NEPOOL's reliability requirement. *See* 587 F.2d at 1300-03. We did so despite the fact that "the purpose behind the deficiency charge" was "to motivate participants to develop sufficient capacity to meet their load requirements." *Id.* at 1302. Indeed, we held it "sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge." *Id.* Petitioners are thus compelled to concede that the Commission may directly establish prices for capacity – or much the same, prices for failing to acquire enough capacity – even for the express purpose of incentivizing

construction of new generation facilities. That the Commission may do so directly would seem to include the power to do so indirectly by setting a target for capacity demand and using a market mechanism to locate the price appropriate to that quantity.

In fact, LSEs have various means of responding to the incentives produced by increases in the ICR short of building new capacity. Public regulators aren't even confined to a choice between allowing construction of new capacity or paying escalating costs. They may also seek capacity from interconnected utilities outside the New England power system or "demand response" contracts where users are compensated for committing to use less electricity during shortages. *See ISO New England,* 120 F.E.R.C. ¶ 61,234, at 61,978 (2007). The Commission explained:

> 'capacity' . . . is the product, and electrical generating capacity is one means, but not the only means, of producing that product. [An] LSE could fulfill its capacity obligation to ISO-NE by constructing new electrical generating capacity but it could also add 50 MW of demand response and 50 MW of capacity contracts (from inside or outside the state), or any mix of the above. If a state wishes to place controls on the amount or type of electrical generating capacity built within that state, or at particular locations within that state, the Commission's regulation of ISO-NE's calculation of ICR does not prevent it from doing so. The

> capacity requirement that ISO-NE places on an individual LSE may be a factor in a state's ultimate determination as to how much electrical generating capacity is built, and where and by whom. These are not, however, the same determinations. . . .

Id. (footnotes omitted). Given this, petitioners' observation that public utilities have overwhelmingly responded to increases in the ICR by choosing to allow construction of new facilities over other alternatives has little relevance. *See* Petrs.' Opening Br. 36-37. This bare fact demonstrates only that this option may be the cheapest, easiest, or most palatable of the choices presented. In current market contexts, constructing new generation facilities in response to a higher ICR may even feel like an imperative. But petitioners have posited no source for that feeling other than internalization of the true costs of the alternatives, which is not only a requirement for efficient market outcomes, but, again, something the Commission may concededly pursue.

Petitioners also appear to argue that the Commission has exceeded its jurisdiction not by directly compelling construction of new generation facilities, but by compelling LSEs to acquire a particular amount of capacity. This argument fails for three interconnected reasons.

First, nothing in the Federal Power Act expressly proscribes requiring LSEs to pay for a certain amount of capacity. Section 201 prohibits the Commission from regulating generation facilities but says nothing

about its power to review the capacity requirements that an entity like ISO-NE imposes on member LSEs. Petitioners thus invoke other provisions to support their argument that the Commission lacks jurisdiction to compel LSEs to buy specified amounts of capacity. These include section 207, which allows the Commission, "upon complaint of a State commission, . . . [to] determine the proper, adequate, or sufficient service" required from an interstate utility and to "fix the same by its order," 16 U.S.C. § 824f, and section 215, a reliability provision whose savings clause states that "[t]his section does not authorize . . . the Commission . . . to set and enforce compliance with standards for adequacy or safety of electric facilities or services," 16 U.S.C. § 824o(i)(2). Neither section, however, unambiguously prohibits the Commission from requiring LSEs to obtain adequate capacity. Section 207 actually grants authority to the Commission, and even if the clause "upon complaint of a State commission" is read as "only upon complaint of a State commission," this section seems to be about energy itself rather than capacity, *see* § 824f ("[T]he Commission shall have no authority to compel . . . the public utility to sell or exchange *energy* when to do so would impair its ability to render adequate service to its customers." (emphasis added)). Nor does anything in section 215(i) prohibit the Commission from requiring capacity purchases – as a savings clause, it deals only with the authority that section provides rather than what the Act as a whole forbids, *see* § 824o(i).

Second, even if sections 207 and 215 clearly prohibited the Commission from requiring LSEs to obtain a particular amount of capacity, this isn't the authority the Commission claims. Instead, the Commission claims authority to review the capacity charges that ISO-NE imposes on member utilities to ensure they are just and reasonable. Because the ICR impacts those charges in two ways – by affecting the market clearing price for capacity in the Forward Market and by affecting the size of each LSE's proportionate share of the ICR – the Commission claims authority to review it as an integral determinant of the transmission tariffs within its jurisdiction. Petitioners point to nothing in the record to suggest that the Commission seeks authority to set a reliability requirement rather than to ensure that the capacity charges actually imposed by ISO-NE are fair to suppliers and consumers. That reasonable concerns about system adequacy might factor into the fairness of those charges is precisely what brings them within the heartland of the Commission's section 206 jurisdiction, *see* § 824e(a).

Third, even if these statutory provisions could be read to prohibit the Commission from requiring LSEs to make adequate capacity purchases, and even if that is what the Commission is doing, this particular camel has long since entered – indeed, ransacked – the tent. Again, three decades ago in *Municipalities of Groton*, we sustained the Commission's assertion of jurisdiction over "deficiency charges" NEPOOL imposed on member LSEs that came up short on their

capacity requirements. *See* 587 F.2d at 1300-03. There, the Commission determined that the deficiency charges, which escalated in both amount and rate based on the proportion by which an LSE fell short, unduly discriminated against smaller entities, which would tend to miss by a greater relative proportion if they missed at all. *See id.* at 1302-03. We thought it irrelevant that the deficiency charges were "designed as an incentive" for the purchase or construction of adequate capacity so long as the charges affected transmission rates otherwise within the Commission's jurisdiction. *Id.* at 1302. To be sure, *Municipalities of Groton* dealt with a different issue – how to calculate the deficiency charge rather than the capacity requirement below which the deficiency charge kicked in. But that distinction makes no difference. For one thing, the ICR does affect the rate of the capacity charge: by changing the clearing price in the Forward Market, it affects not only each LSE's share of the ICR, but also the price point paid for capacity. Moreover, while the size of the capacity requirement was not directly implicated in *Municipalities of Groton,* it would be odd if the Commission could determine that the rate of the deficiency charge was unfair but could say nothing about a capacity requirement triggering those charges at levels grossly unfair to suppliers or consumers.

Mississippi Industries v. FERC is similarly fatal to petitioners' argument. *See* 808 F.2d 1525, *vacated in part on other grounds,* 822 F.2d 1104 (D.C. Cir. 1987). There we held that the Commission's authority

over practices affecting rates allowed it to review the allocation of capacity costs among the various entities in the Middle South Utilities system. *See id.* at 1540-45. We emphasized that "[c]apacity costs are a large component of wholesale rates," and agreed with the Commission that, "in light of the [Middle South system's] integrated planning for generating capability on a system basis," the Commission could appropriately reallocate those costs among the Middle South companies to prevent unfairness to particular consumers. *Id.* at 1541. Petitioners think that *Mississippi Industries* is irrelevant because the Middle South system involved a level of integration unknown in New England. But even if the level of integration at issue in *Mississippi Industries* was unusual at the time or remains unusual today, "integrated planning . . . on a system basis," *id.* at 1541 (emphasis omitted), is a long-standing feature of the New England bulk power system, at least as far as capacity decisions are concerned. *See, e.g., Municipalities of Groton,* 587 F.2d at 1300-03. Thus, *Mississippi Industries*, together with *Municipalities of Groton,* teaches that there is nothing special about capacity decisions that places them beyond the Commission's jurisdiction. Where capacity decisions about an interconnected bulk power system affect FERC-jurisdictional transmission rates for that system without directly implicating generation facilities, they come within the Commission's authority.

Finally, petitioners argue that the ICR has no effect on FERC-jurisdictional rates at all because, as a matter of economic theory, the supply of capacity is actually perfectly elastic and hence fixed at the long run cost of new entry. As petitioners candidly conceded at oral argument, this may be true in the theoretical world of economics textbooks, but is almost certainly false in the real world outside them. Oral Arg. Tr. 10-13. And even granting the hypothesis that the market clearing price will equal the average cost of entry for the mix of suppliers capable of providing capacity over the relevant three-year run, the point of an auction mechanism like the Forward Market is to use a best approximation of demand and the power of competitive bidding to help locate that price. Clairvoyant commissioners would have no need for such a useful pricing device, but the real world decision makers who use the Forward Market do so precisely for its ability to evaluate prices. Thus, even if all the ICR did was help to find the right price, it would still amount to a "practice . . . affecting" rates. § 824e(a).

III.

Determination of the ICR affects rates within the Commission's jurisdiction and, in evaluating whether that determination is just and reasonable, the Commission neither regulates generation facilities in violation of section 201 nor runs afoul of any other

provision of the Federal Power Act. The petitions for review are accordingly denied.

So ordered.

APPENDIX B

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 07-1375 **September Term, 2008**
FILED ON: June 23, 2009

CONNECTICUT DEPARTMENT OF PUBLIC UTILITY CONTROL,
PETITIONER

v.

FEDERAL ENERGY REGULATORY COMMISSION,
RESPONDENT

NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE, ET AL.,
INTERVENORS

Consolidated with 07-1460, 08-1175

On Petitions for Review of Orders
of the Federal Energy Regulatory Commission

Before: TATEL, GARLAND, and GRIFFITH, *Circuit Judges*.

JUDGMENT

These causes came on to be heard on the petitions for review of orders of the Federal Energy Regulatory Commission and were argued by counsel. On consideration thereof, it is

ORDERED and **ADJUDGED** that the petitions for review are denied, in accordance with the opinion of the court filed herein this date.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

By /s/ _____
Michael C. McGrail
Deputy Clerk

Date: June 23, 2009

Opinion for the court filed by Circuit Judge Tatel.

APPENDIX C

118 FERC ¶ 61,157
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

ISO New England, Inc
New England Power Pool

Docket No. ER07-365-000

ORDER ACCEPTING TARIFF CHANGES AND REQUIRING COMPLIANCE FILING

(Issued February 28, 2007)

1. In this order, the Commission accepts proposed tariff changes jointly filed by ISO New England, Inc. (ISO-NE) and the New England Power Pool Participants Committee (NEPOOL) to revise ISO-NE's Market Rule 1 to formalize the processes and methodologies used to determine the Installed Capacity Requirements (ICR) for the New England Control Area, and requires a compliance filing with regard to those changes.

Background

2. In 2006, the Commission approved a settlement agreement pursuant to which New England market participants will develop a forward capacity market

(FCM Settlement).[1] In order to accommodate the FCM Settlement, ISO-NE and NEPOOL have revised portions of the process for developing the ICR.

3. The ICR is the amount of resources needed to meet the reliability requirements defined for the New England control area: it is a projection of the minimum amount of capacity required to serve load (*i.e.*, peak demand for electricity) reliably in the New England region. The ICR is the total number of MW that Load Serving Entities (LSEs) will be required to purchase through the Forward Capacity Auctions, and thus a primary determinant of capacity prices. The ICR is determined in accordance with existing resource planning reliability criteria, the goal of which is to ensure that resources are planned and installed such that the probability of disconnecting non-interruptible customers due to deficiency will be, on the average, no more than once in ten years.[2]

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[1] *Devon Power, LLC* (*Devon Power*), 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006) (jointly, FCM Orders).

[2] ISO-NE's and NEPOOL's proposal also contains new parameters and measurements for related elements of New England's market design, including Local Sourcing Requirements (the minimum amount of capacity that must be located within an import-constrained load zone), and the Maximum Capacity Limits (the maximum amount of capacity that can be procured in an export-constrained load zone to meet the ICR) for use in the FCM. Transmission constraints limit the amount of capacity that can be transferred into import-constrained sub-regions. Thus those sub-regions must procure a minimum number of MWs from within the sub-region to meet

(Continued on following page)

4. The method for determining ICR is not currently described in the market rules. Historically, ISO-NE, with input from participants, established ICR values prior to the beginning of the ISO-NE power year (on a MW basis for each month of the power year).[3] These values were filed annually with the Commission pursuant to the ISO-NE tariff.[4] Each market participant had a capacity responsibility in each month to procure a proportional share (based on the participant's share of peak load) of the applicable ICR value. A participant was able to satisfy its capacity obligation through several means, including bilateral contracting, ISO-administered auctions, owning generation facilities, and demand-side resources.

5. Pursuant to section 205 of the Federal Power Act (FPA), on December 22, 2006, ISO-NE and NEPOOL jointly submitted proposed revisions to the ISO-NE tariff that are designed to memorialize the processes and methodologies used to determine the ICR.

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system-reliability requirements. As part of the ICR process, ISO-NE will determine the Local Sourcing Requirement and the Maximum Capacity Limit prior to each forward capacity auction.

[3] ISO-NE's Power Year runs from June 1 through May 31 of the following year.

[4] ISO-NE Tariff, former Market Rule 1 at section III.8.1 (*see ISO New England, Inc.*, 115 FERC ¶ 61,149 at P 2 n. 2 (2006) ("Under section III.8.1 of Market Rule 1 . . . the ISO calculates the IC Requirements each Power Year and, after consultation with stakeholders (as required by the Participants Agreement), ISO-NE must file the [Installed Capacity] Requirements with the Commission pursuant to section 205 of the FPA").

ISO-NE and NEPOOL state that the proposed revisions neither significantly change the existing methodology to calculate ICR nor alter the reliability criteria with which the ICR must comply.[5] The proposed revisions do, however, alter existing processes for establishment of the ICR, as necessary to accommodate the FCM. Under FCM, ISO-NE will hold auctions for capacity three years in advance, and so ICR will similarly need to be calculated in advance by using "assumptions . . . regarding the resources that will be available resources and the forecasted load for the relevant time period."[6] ISO-NE has utilized the Westinghouse/ABB Capacity Model Program in establishing New England's annual ICR values, and has formulated assumptions regarding generating and demand response resources, system load forecasts, and the reliability benefits from direct connection to the neighboring power systems of Quebec, New York and the Canadian Maritimes (tie benefits) which it has incorporated into those models.[7] The modeling to be conducted pursuant to sections III.12.6, III.12.7, III.12.8, and III.12.9 of the proposed

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[5] The reliability criteria used for calculating ICR comport with the requirements of the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC).

[6] Transmittal at 2.

[7] The Westinghouse Model is a computer program that calculates system Loss of Load Expectation (LOLE) using probabilistic mathematics based on a range of potential load and capacity conditions.

tariff revisions is a comprehensive process, such that the respective results of the modeling in those sections cannot be used independently.[8]

6. ISO-NE and NEPOOL state that the proposed revisions to Market Rule 1 are not comprehensive: some details of calculating ICR and Local Sourcing Requirements will be reflected in the ISO's annual filing of ICR values as part of the FCM process. For example, the proposed provisions anticipate that generator availability metrics will evolve over time and that detailed generator availability assumptions will be reflected in the annual filings. These annual filings will provide a forum in which the Commission will review whether the ICR and Local Sourcing Requirement values are just and reasonable, and interested stakeholders will continue to have the opportunity to raise their concerns at that time. ISO-NE and NEPOOL state that the ICR rules proposed in the instant filing will define the process for calculating ICR, whereas the annual filings will identify the assumptions used to calculate the ICR for a given period and identify the resulting numerical values.

7. ISO-NE and NEPOOL conducted an extensive stakeholder process. The proposed market-rule revisions were considered by stakeholders and

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[8] For purposes of the modeling in those sections, demand resources will be treated in a manner comparable to supply resources.

received an 80.55 percent vote in support from the NEPOOL Participants Committee.

8. ISO-NE and NEPOOL request that the Commission allow the proposed revisions to become effective on March 1, 2007. ISO-NE and NEPOOL state that participants need to have some certainty as to the ICR, Local Sourcing Requirements and Maximum Capacity Limits that will be in effect for the initial forward capacity auction.[9]

Protests and Comments

9. The filing was noticed in the Federal Register,[10] with interventions, comments or protests due by January 16, 2007. NEPOOL, Constellation Energy Commodities Group *et al.* (Constellation), the New York State Reliability Council (NYSRC), H.Q. Energy Services (U.S.), Inc. (HQUS), Consolidated Edison Energy, Inc. (Con Ed), the Long Island Power Authority (LIPA), Exelon Corporation (Exelon) and the Connecticut Department of Public Utility Control (CT DPUC) filed timely motions to intervene and protests or comments. National Grid USA (National Grid), Milford Power Company, the Massachusetts Department of Telecommunications and Energy, the New York Independent System Operator, Dominion

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[9] Under the Settlement Agreement, the first forward capacity auction is intended to occur in early 2008 for a Capacity Commitment Period beginning June 1, 2010.

[10] 72 Fed. Reg. 775 (2007).

Energy Marketing *et al.*, New England Conference of Public Utilities Commissioners, Northeast Utilities Service Company, NRG Companies and NSTAR Electric and Gas Company filed timely motions to intervene.

10. ISO-NE, NEPOOL and National Grid, *et al.*, filed motions for leave to answer and answers to the protests and comments above. United Illuminating Company also sought leave to intervene out of time. LIPA opposed ISO-NE's motion to file an answer; alternatively, if the Commission allows ISO-NE's answer, LIPA moves for the establishment of a technical conference to clarify what it characterizes as ISO-NE's violation of the FCM Settlement, and the basic functioning of the FCM operations with respect to imports and exports of capacity. The NYSRC also filed motion for leave to file an answer, and an answer to ISO-NE's answer.

Discussion

Procedural Matters

11. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214 (2006)), all timely filed motions to intervene and any motions to intervene out-of-time filed before the issuance date of this order are granted. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R.

§ 385.213(a)(2) (2006), prohibits an answer to an answer unless otherwise ordered by the decisional authority. We will accept ISO-NE's, NEPOOL's, National Grid's answers because they have provided information that assisted us in our decision-making process. We deny LIPA's motion for a technical conference, on grounds discussed *infra*. We are not persuaded to accept the NYSRC's answer to ISO-NE's answer, and therefore reject it.

Analysis

Jurisdiction and Standard of Review

Protests

12. In its protest, the CT DPUC asserts that the Commission does not have jurisdiction to establish a methodology for the determination of ICR, since that would exceed the authority granted to the Commission by Congress in the FPA. The CT DPUC argues that the FPA expressly directs that the Commission "shall not have jurisdiction . . . over facilities used for the generation of electric energy." The CT DPUC argues that, while the Commission has the authority to establish the price of capacity or how capacity requirements will be allocated among LSEs, it does not have jurisdiction to dictate the amount of ICR that must be purchased. The CT DPUC asserts that the New England states have demonstrated cooperation in developing regional capacity requirements and that acceding to the New

England states' authority to set resource requirements will not jeopardize regional reliability.

13. ISO-NE and NEPOOL note that litigation regarding the Commission's authority to establish the ICR is currently pending before the U.S. Court of Appeals for the District of Columbia Circuit.[11] These proposed rules governing the establishment of the ICR values were developed presuming that the Commission's determination of its authority over the ICR would be sustained by the Court. ISO-NE and NEPOOL state that, to the extent that the Court concludes otherwise, revisions to the ICR-related Market Rule provisions will be developed and filed with the Commission in the future. In their answers, ISO-NE and NEPOOL additionally note that the CT DPUC participated extensively in the stakeholder process that led to NEPOOL's determination of ICR, and it is thus inappropriate to consider CT DPUC to have been deprived of the opportunity to participate in the development of ISO-NE's ICR methodology.

14. Con Ed argues that the correct standard of review for the Commission's consideration is not whether the proposed filing is "just and reasonable." Con Ed argues that this standard or [sic] review applies to utility rates, not system adequacy or reliability standards. Con Ed contends that the ICR

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[11] *See Connecticut Department of Public Utility Control* v. *Federal Energy Regulatory Commission (CT DPUC)*, Docket No. 05-1411.

methodology is subject to the Administrative Procedure Act's "substantial evidence" standard. According to Con Ed, the "just and reasonable" standard as applied in the cases cited by ISO-NE arose in the context of utility rates, and that, since ICR is a reliability standard rather than a utility rate, it is not subject to the "just and reasonable" standard.

Commission Decision

15. The Commission finds that it has jurisdiction to consider the proposed mechanism for the determination of ICR. As noted above, the question of the Commission's jurisdiction over ICR is already on appeal in the D.C. Circuit. As the Commission stated in its order accepting the FCM Settlement, however, the FCM settlement "establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales, bringing it squarely within the Commission's jurisdiction under the FPA."[12] Thus, in this context, the ICR is one of the principal determinants of the price of capacity and, hence, falls within the Commission's jurisdiction to review "any rate, charge or classification" charged by a public utility for electric transmission or sales subject to agency jurisdiction, and "any rule, regulation, practice, or contract

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[12] *Devon Power* at P 201.

affecting such rate, charge or classification."[13] ISO-NE's mechanism to determine ICR is a "practice . . . affecting" the price of capacity, and as such falls within the Commission's jurisdiction.

16. This determination is consistent with prior court decisions regarding the Commission's jurisdiction over capacity requirements and charges. *See Municipalities of Groton* v. *FERC* (*Municipalities of Groton*),[14] in which the U.S. Court of Appeals for the D.C. Circuit upheld the Commission's jurisdiction to review the capability responsibility charges made by NEPOOL to each NEPOOL member for that member's share of capacity responsibility for the pool's peak load, and stated that the charges came within "the Commission's inclusive jurisdictional mandate – which reaches . . . practices . . . 'affecting' [jurisdictional] transmissions or services."[15] The D.C. Circuit similarly held that the Commission had jurisdiction over the allocation of capacity and costs of a nuclear plant among multiple operating companies of an integrated utility system, because "while [provisions allocating capacity] do not fix wholesale rates, their terms do directly and significantly *affect*

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[13] FPA section 206(a), 16 U.S.C. § 824e(a).

[14] 587 F.2d 1296 (D.C. Cir. 1978).

[15] *Id.* at 1302.

the wholesale rates at which the operating companies exchange energy."[16]

17. This view is also consistent with the Commission's recent order conditionally accepting the market redesign for the California Independent System Operator (CAISO),[17] in which the Commission addressed similar jurisdictional concerns. In response to the assertion that resource adequacy requirements were outside of the Commission's purview, the Commission stated:

> [W]here an interconnected transmission system is operated on a regional basis as part of an organized market for electricity . . . all users of the system are interdependent, particularly with respect to reliability, *i.e.*, one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining

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[16] *Mississippi Industries* v. *FERC*, 808 F.2d 1525, 1542 (emphasis in original), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1978).

[17] *Cal. Indep. Sys. Operator Corp.* (*CAISO*), 116 FERC ¶ 61,274 (2006), *reh'g pending*.

> whether rates remain just and reasonable and not unduly discriminatory.[18]

18. The Commission further stated that "resource adequacy plays an important role in addressing whether Commission-jurisdictional wholesale prices reflect the exercise of market power or the scarcity of supply."[19] Noting that it was also approving bid caps for energy markets in California, the Commission stated:

> These bid caps are premised on the notion that bids above these levels may not reflect true scarcity pricing, but rather the exercise of market power or abuse that results in rates that are not just and reasonable. This premise is only valid, however, if there is some mechanism – other than energy price increases – to encourage the construction of new generation where and when needed. Consequently, in the absence of a workable resource adequacy program, it would be difficult for us to approve such bid caps. Without a workable program, the bid caps would simply inhibit new supply, and thereby harm customers, rather than

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[18] *CAISO* at P 1113, *citing Cal. Indep. Sys. Operator Corp.*, 115 FERC ¶ 61,172, at P 36 (2006) and *Gainesville Utils. Dep't* v. *Fla. Power Corp.*, 402 U.S. 515, 529 (1971) (Commission has the "responsibility to the public to assure reliable efficient electric service").

[19] *CAISO* at P 1114.

protecting customers from the exercise of market power or abuse.[20]

19. Similar considerations apply in New England. The ICR requirement in issue here is an integral component of the charges that ISO-NE makes to its member LSEs.[21] Because ISO-NE will determine a single ICR requirement for its entire system (later to be subdivided among its LSEs), the Commission is required to review ISO-NE's ICR methodology to ensure that these charges, which are levied on all LSEs, are determined in a just and reasonable manner. Additionally, ISO-NE, like CAISO, has bid caps in its energy markets, and similarly in New England, absent an affirmative mechanism to elicit the construction of new supply, those bid caps would simply harm customers by discouraging such construction, rather than protecting customers from the exercise of market power or abuse.

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[20] *Id.*

[21] As the CT DPUC acknowledges,

> ICR plays a pivotal role under the FCM Settlement in determining how much capacity New England's electric customers must procure. A key feature of the FCM Settlement is that the amount of capacity purchased in the [Forward Capacity Auction] will equal one hundred percent of ICR. Thus, to the extent that ICR is greater than the amount needed to ensure reliability, customers will buy more capacity than is just and reasonable.

CT DPUC protest at 4, *citing* FCM Settlement, section 11.III.C.

20. The CT DPUC asserts that the FPA expressly states that the Commission does not have jurisdiction over facilities used for the generation of electric energy, and thus the Commission has no jurisdiction to establish a methodology for determining ICR. This argument is inapposite. The Commission is not asserting jurisdiction over generating facilities. It is asserting jurisdiction over an essential component of the charge for wholesale capacity in interstate commerce. In doing so, the Commission is not requiring that any individual state build generation or that any participant satisfy its capacity obligation via a particular resource or set of resources. Furthermore, the Commission notes that under the previous capacity market design in New England, a participant was not limited to generation resources in satisfying its capacity obligation. Participants were able to satisfy their capacity obligations via a variety of resources, including bilateral purchases of capacity, demand-side resources and combinations thereof. The Commission notes that the FCM Settlement Agreement provides for procurement of that same variety of resources, and thus does not require states to construct new generation resources. Finally, ISO-NE and NEPOOL state that the proposed provisions are not intended to supplant ISO-NE's annual filing of ICR values for Commission review. The Commission finds that it is just and reasonable for the Commission to consider ISO-NE's projection of the minimum amount of capacity necessary to reliably serve load.

21. Moreover, as we stated in *CAISO*, the Commission's responsibility to assure that wholesale rates are just and reasonable does not mean that we cannot, when appropriate, accept state determinations regarding resource adequacy requirements. In *CAISO* we stated that we could, "in appropriate circumstances, defer to state and Local Regulatory Authorities to set" resource adequacy requirements.[22] In this case, however, there is no proposal for us to consider that has been put forward by all of the New England states. The CT DPUC argues that we should not determine the ICR, but there has been no agreement among the New England states to establish an ICR and, accordingly, the CT DPUC's argument would simply create a gap. While we could, in appropriate circumstances, accept an agreement among the states or other regulatory authorities within a multi-state transmission organization to establish a reserve margin or other resource adequacy component of wholesale charges if we determined the arrangement was just, reasonable and not unduly discriminatory, that is not the situation presented to us here. There is no agreement among the New England states to establish the ICR and therefore nothing to which we could defer. We therefore act today to establish an integral component of the jurisdictional charge for wholesale capacity within New England to ensure that

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[22] *CAISO* at P 1117.

wholesale rates are just, reasonable and not unduly discriminatory.

22. For similar reasons, the Commission further finds that the appropriate standard of review is whether the ICR mechanism is just and reasonable. Con Ed's suggestion that the Administrative Procedure's "substantial evidence" standard be used instead is based on a court decision involving not section 205, but section 18 of the FPA.[23] ICR, by contrast, is a primary component of the payment for capacity that ISO-NE charges – therefore, a component of a "rate, charge or classification" charged by a public utility under section 205. Thus, the appropriate standard of review is the "just and reasonable" standard of section 205.

Allocation of Interface Capacity between Tie Benefits and Firm Capacity Imports

23. Tie benefits represent the amount of emergency assistance that may be available from the

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[23] *Bangor Hydro-Electric Co.* v. *FERC*, 78 F.3d 659, 663 fn. 3 (D.C. Cir. 1996). In that case, which involved the Commission's granting of a license to a hydroelectric plant rather than the Commission's review of rates, the Court was considering a case involving section 18 of the FPA, 16 U.S.C. § 811, under which "[t]he Commission shall require the construction, maintenance, and operation by a licensee at its own expense of . . . such fishways as may be prescribed by the Secretary of the Interior or the Secretary of Commerce, as appropriate."

interconnections with directly connected control areas.[24] According to ISO-NE, tie benefits are a result of resource and load diversity between two control areas; for example, when New York has excess resources at a time when New England's resources are tight, New York resources could support New England's load to the extent that transmission constraints allow. Under ISO-NE's proposal, tie benefits reduce the amount of ICR needed to ensure reliability. Thus, for example, if ISO-NE determines that it needs 30,000 MW of installed capacity in order to meet its reliability objective and it determines that tie benefits total 1,000 MW, the ICR would be 29,000 MW. In this case, LSEs in the aggregate would need to acquire 29,000 MW of capacity through the FCM auction. The remaining 1,000 MW of capacity needed for reliability (the tie benefit) would be assumed to be available in an emergency from the neighboring control area without capacity payments made during the FCM auction.[25]

24. Section III.D.4(a) of the FCM Settlement Agreement provides that the total amount of tie benefits assumed over a particular interface, plus the

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[24] New England is directly connected to New York, New Brunswick and Hydro Quebec.

[25] Though New England would not make capacity payments to the neighboring control area, New England would need to make energy payments to the neighboring control area to the extent that the neighboring control area provided energy to New England during an emergency.

import capacity resources over that interface, cannot exceed the physical transfer capability of that interface. ISO-NE states that the settlement agreement left open for debate how to allocate the interface capability between capacity import contracts and tie benefits, and there were competing stakeholder views on this issue. Thus, ISO-NE states that in order to maintain the tie benefits the total amount of capacity imports will be limited to the transfer capability with a particular control area, minus the tie benefits assumed over that interface. ISO-NE's rationale is that the transfer capability is paid for by ultimate consumers through Network Load charges, and thus, ultimate consumers should have the right to benefit from the reduced ICR that will result from the maintenance of free-flowing ties (*i.e.*, tie benefits) between two directly connected control areas. Thus, the proposed rules require that the total amount of imports from a particular control area, plus the tie benefits with that control area, cannot exceed the transfer capability with that control area.[26] At their December 8, 2006 meeting, the NEPOOL Participants

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[26] *See* Transmittal at 13 n. 28:

> In order for tie benefits to occur, a portion of the interface must be free from long-term capacity commitments. Firm capacity contracts require a portion of a tie to be reserved. Because the ISO cannot double count transfer capability, the transfer capacity for tie benefits is reduced and tie benefits themselves may be reduced also. Thus, firm capacity imports over ties effectively lowers the transfer limits available to support tie benefits.

Committee voted on an alternative approach that would have afforded imports a preference over tie benefits clearing in the capacity auction at external interfaces other than the HQ Interconnection. That approach failed to garner the requisite level of support.[27]

Protests

25. Constellation and HQUS argue that capacity imports, supported by contractual obligations to deliver energy when called upon, should be able to have access to the transfer capability and thereby reduce the amount of transfer capability remaining available for tie benefits.

26. Constellation argues that the approach proposed by ISO-NE and NEPOOL, which limits the import transactions across ties with areas directly connected to ISO-NE's control area, compromises reliability, and that allowing parties with contractual obligations to access a transmission tie up to the total capacity transfer capability will allow parties to meet capacity requirements at least cost, and that taking away tie line capability will only make it increasingly difficult to import capacity into areas exhibiting the greatest needs. Constellation further argues that, given that

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[27] Preliminary Minutes of the December 8, 2006 NEPOOL Participants Committee meeting. *See* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2007/jan52007/supp_notice_jan0507.pdf.

New England's FCM will measure generator performance and availability during the most critical hours of the year for reliability assurance,[28] reliability concerns cannot be met simply by relying on open transmission ties and hoping that capacity becomes available over those transmission resources when called upon during critical hours. Constellation argues that participants' reliability needs are best served by enabling parties to contract for capacity over such transmission ties in advance of critical hours.

27. HQUS asks the Commission to reject the decision to include tie benefits from New York and New Brunswick AC transmission ties in the ICR-reform process. HQUS asserts that proposed section III.12.10 of Market Rule 1 would prohibit capacity imports from New York and New Brunswick in order to leave transmission capacity available for the maximum amount of probabilistic tie benefits, and that this practice prohibits real transactions with New York and New Brunswick in favor of a calculation of the probability that there will be capacity available in an emergency through reliance on transmission tie benefits. HQUS further argues that as a result of this practice, during a capacity

[28] Under the Forward Capacity Market, generation availability will be measured according to "shortage events." This approach is intended to measure generator performance during hours when capacity resources are determined to be most needed due to conditions on the system.

emergency, system operators will rely on a calculation of capacity assistance that an adjacent control area could provide, as opposed to capacity actually under contract and which should, therefore, be more reliable.

28. HQUS further notes that Hydro Quebec Interconnection contracts for capacity have some precedence over tie benefits through the reduction of Hydro Quebec Interconnection Capability Credits (for a transmission owner who has sold its transmission rights). Thus, HQUS asserts that market rules treat the Québec transmission tie differently, allowing real capacity to displace transmission tie benefits, and argues that ISO-NE should treat imports from New York and New Brunswick similarly to the way it treats imports from Québec.[29]

29. National Grid states in its reply that, contrary to protesters' argument that capacity imports provide more reliability and value to market participants than tie benefits, the opposite is true: tie benefits are

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[29] As a separate issue, HQUS states that in orders since 2001, the Commission has permitted ISO-NE to assign Hydro-Québec Interconnection Capacity Credits (HQICCs) to the interconnection rights holders (IRHs) based on the IRHs' support of the Phase I/II facilities in New England, rather than based on contractual rights to capacity from Hydro-Québec. HQUS disagrees with this methodology and has pursued its counterarguments in the several prior HQICC proceedings. Since HQUS notes that it is raising this issue simply to note that it is reserving its right to raise this issue in future filings, the Commission will not address this argument here.

calculated using extensive probabilistic analysis and independent ISO-NE studies that consider all of the resources that could be present (or absent) at a time of shortage, not just the subset of import contracts, and that tie benefits will ultimately provide more reliability assistance to New England than import contracts.

Commission Decision

30. We will accept ISO-NE's proposal to set aside interface transfer capability for tie benefits. We agree with ISO-NE that since loads within New England jointly share the costs of the transfer capability, loads should jointly share the benefits of that capacity, including the tie benefits and the associated reduction in ICR. Constellation and HQUS object to ISO-NE's proposal to set aside transfer capability associated with the tie benefit; they recommend that the transfer capacity be eligible to support capacity imports even in cases where such imports reduce the tie benefit. But purchasing capacity imports that reduce tie benefits would needlessly increase aggregate capacity costs; it would increase capacity purchases from neighboring control areas with no corresponding reduction in the need for capacity purchases within New England, for the following reason.

31. Under ISO-NE's proposal, tie benefits reduce the amount of the ICR. Under the terms of the FCM Settlement Agreement, capacity imports from a

specific neighboring control area plus tie benefits from that control area cannot exceed the transfer capability with that control area. Under the rules proposed in the instant filing, LSEs may use only the transfer capability in excess of tie benefits to import capacity. Constellation and HQUS propose that capacity imports, supported by contractual obligations to deliver energy when called upon, should be allowed even when they reduce the amount of tie benefits. But since tie benefits reduce the amount of the ICR, capacity imports that reduce the tie benefit would increase the ICR by the amount of the lost tie benefit. Thus, purchasing imported capacity that reduces the tie benefit would unnecessarily increase the amount of capacity that must be purchased and the associated costs of acquiring capacity by customers in New England.

Treatment of Specific Tie Benefits Provided by Cross-Sound Cable

Protest

32. LIPA asserts that ISO-NE's filing is unjustly discriminatory, in that it does not account in a similar manner for the tie benefits from similarly-situated transmission resources.

33. LIPA states that, under the proposed market rules, section III.12.9 of Market Rule 1 provides that tie benefits with neighboring control areas should be calculated by using a probabilistic methodology that quantifies firm capacity equivalents to express the

probable amount of capacity that will be available on the interface. The Cross Sound Cable, an interface between New York and New England on which LIPA owns all of the firm transmission rights, will be subject to this definition. ISO-NE's market rules provide for a different methodology, however, for calculating the tie benefits provided by the Hydro-Quebec Phase II Interconnection (HQ Interconnection) between New England and the Hydro-Quebec control area – namely, a deterministic methodology that uses forecasted load and capacity for the Hydro-Quebec control area and the HQ Interconnection transfer limit as determined by ISO-NE to arrive at a specific amount of capacity that will be available for tie benefits on the HQ Interconnection interface.[30]

34. LIPA asserts that these two interties between New England and neighboring control areas are equivalent, in that they are both privately-owned, are both high voltage direct current (HVDC) facilities, function in the same manner (*i.e.*, both the HQ Interconnection and the Cross Sound Cable are direct current (DC) facilities, such that the direction of flows

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[30] The difference in treatment here means that parties utilizing the HQ Interconnection will have a higher degree of certainty as to the amount of capacity that will be available to them than parties utilizing the Cross Sound Cable. Thus, transmission capacity across the HQ Interconnection is likely to receive a higher price than transmission capacity across the Cross Sound Cable and other transfer facilities as to which there is a lesser degree of certainty.

can be controlled), and should therefore have their tie benefits calculated in a similar way. LIPA argues that a similar methodology to measure the tie benefits for both of those facilities (*i.e.*, a deterministic measure that arrives at a definitive result, rather than a probabilistic measure that develops a probable result) is more appropriate for both the HQ Interconnection and the Cross Sound Cable than the probabilistic method for alternating current (AC) interface facilities, where the flows cannot be controlled, contained in the proposed ICR rules, and that it is discriminatory not to calculate the tie benefits provided by the HQ Interconnection and the Cross Sound Cable in a similar manner.

Commission Decision

35. The Commission denies LIPA's request. While LIPA correctly notes that the HQ Interconnection and the Cross Sound Cable are HVDC, controllable interconnections, there are other important differences between the two facilities.

36. ISO-NE is required to submit specific HQ Interconnection values, as required in a prior Commission order.[31] In that order, the Commission noted that the applicants provided that the deterministic method was appropriate there because all of the capacity transferred from the HQ control area to New

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[31] *New England Power Pool*, 111 FERC ¶ 61,132 (2005).

England are sent through the HQ Interconnection. Thus, the determination of tie benefits available through the HQ Interconnection was based on the availability of all of the generating capacity from Quebec that can be accessed through the HQ Interconnection, rather than on an estimate of the likelihood that New England would require emergency assistance.[32]

37. Equivalent treatment for the Cross Sound Cable, however, would ignore the fact that when capacity is transferred from New York to New England, that transfer occurs across the Cross Sound Cable and also across other transmission interfaces between the two control areas. Those other transmission interties are AC facilities,[33] so it is not possible to know in advance how much capacity will flow through those facilities. Therefore, it is similarly not possible to know in advance how much transmission capacity on the Cross Sound Cable will be necessary at any given time for emergency assistance. Given this difference, the Commission will not direct

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[32] *Id.* at P 8.

[33] Those additional facilities are: Pleasant Valley – Long Mountain 345 kV (398) Line, Alps – Berkshire Northfield 345 kV (393/312) Line, Rotterdam – Bear Swamp 230 kV (E205W) Line, Northport – Norwalk Harbor 138 kV (1385) Line, Whitehall – Blissville 115 kV (K37) Line, Hoosick – Bennington 115 kV (K6) Line, and Plattsburgh-Sandbar 115 kV (PV-20) Line. *See* 1992-1996 NYPP – NEPOOL Transfer Limit Study, http://www.iso-ne.com/trans/sys_studies/rsp_stud/other/tfer_limit_study92-96_nypp_nepool.pdf.

ISO-NE to quantify the tie benefits on the Cross Sound Cable in a similar way to its treatment of the HQ Interconnection.

Exports Across a Constrained Region

Protests

38. LIPA states that ISO-NE's filing fails to provide the Market Rules necessary to comply with section III.A.8 of the FCM Settlement Agreement, which states:

> Where zonal separation is determined to exist, Market Rules shall specify a process for an Export both from or through the import-constrained zone over tie lines to external regions.[34]

39. LIPA's interest in this issue stems from its contract with Bear Swamp Power Company LLC (Bear Swamp) to purchase firm capacity and energy from generating capacity located in Massachusetts, for delivery through Connecticut into Long Island by way of the Cross Sound Cable (on which LIPA holds 330 MW of firm transmission rights). LIPA argues that properly accounting for capacity that is exported through a constrained zone should result in increasing the Local Sourcing Requirement in the constrained region, but that ISO-NE's filing fails to

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[34] LIPA protest at 7, *citing* FCM Settlement Agreement, section III.A.8 at 20.

do so. LIPA also quotes from the testimony of ISO-NE witness, Mark Karl in the *Devon Power, LLC, et al.*, proceeding. There, Mr. Karl testified that firm capacity exports could be accommodated by changing the market rules to allow the export to "buy through" the congestion in the capacity market between the Rest-of-Pool zone and an import-constrained zone such as Connecticut. LIPA is concerned that ISO-NE would be free to prevent such exports, in violation of the FCM Settlement Agreement. Indeed, LIPA states that it has been informed by ISO-NE that the ISO may intend to curtail firm capacity exports during periods of transmission constraints. LIPA also argues that curtailing such firm exports would be a violation of interregional agreements, the provisions of which were approved by the Commission in 2001.[35]

40. ISO-NE and NEPOOL disagree with LIPA, arguing that the provisions in the ICR filing are consistent with the FCM Settlement Agreement. ISO-NE states that the proposed ICR rules appropriately consider any exports by not including capacity associated with an accepted Administrative Export De-List Bid in the calculation of the Local Sourcing Requirement or the ICR. In ISO-NE's view, this latter provision is sufficient to ensure that New England does not rely on capacity obligated for export to a neighboring control area. ISO-NE contends that it is not appropriate, or required by the FCM Settlement

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[35] *See New England Power Pool*, 97 FERC ¶ 61,213 (2001).

Agreement, for a capacity export that originates from a resource located outside of an import-constrained zone to result in an increase in the Local Sourcing Requirement for the import-constrained zone. ISO-NE argues that purchasing capacity from a resource located in an unconstrained zone merely provides a right to use that capacity within the unconstrained zone; it does not provide a priority right to export across any specific path, including a constrained path.

Commission Decision

41. We agree with LIPA that the proposed rules in the instant filing do not provide a process for an Export through an import-constrained zone over tie lines to external regions, as required by the FCM Settlement Agreement. We disagree with ISO-NE that merely excluding such de-listed export capacity from the capacity that may be used to satisfy the ICR and Local Sourcing Requirement is sufficient to meet the FCM Settlement Agreement's requirement. While such exclusion would ensure that New England does not rely on exported capacity in meeting its ICR and Local Sourcing Requirement, as ISO-NE argues, that result does not provide a process to allow entities to export capacity through import-constrained zones.

42. We agree with ISO-NE that an entity purchasing capacity from a resource located in an unconstrained zone is not entitled to export the capacity using constrained transmission capacity for

which the entity has not paid for (or otherwise acquired) transmission capacity rights. But ISO-NE's filing provides no process for an entity to acquire such transmission capacity rights. There may be alternative processes that may satisfy the FCM Settlement Agreement's requirement. For example, where transmission constraints could prevent capacity from being exported, one solution might be a process that allows entities to acquire capacity market transmission rights over the applicable congested transmission path at a just and reasonable price. The process described by Mr. Karl of "buying through" the congestion in the capacity market between zones might be such a process.[36] Another process might involve allowing an entity such as LIPA to sell its New England capacity into the FCM auction in the applicable unconstrained zone and to purchase an equivalent amount of capacity in an import-constrained zone (*i.e.*, Rest-of-Connecticut, in LIPA's case) in the FCM. LIPA could then move the purchased capacity over the tie line (*i.e.*, the Cross Sound Cable) into Long Island without relying on congested transmission capacity in New England. Such a purchase would be in addition to the capacity purchased to meet the capacity requirements of LSEs

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[36] To the extent that an entity acquired transmission capacity market rights through an import-constrained zone, the Local Sourcing Requirement in the import-constrained zone may need to increase, since less capacity could be imported from unconstrained zones to meet the reliability needs of loads within the import-constrained zone.

in the import-constrained zone. As a result, the minimum amount of capacity required to be purchased in the FCM in the import-constrained zone would exceed the Local Sourcing Requirement by the amount of the purchase for export. There may be other options that would satisfy the FCM Settlement Agreement's requirement.

43. We will not specify in this order how the FCM Settlement Agreement's requirement must be satisfied, but we will require that ISO-NE file to propose a process for such exports within 180 days of the date of this order.[37] We do not agree with what appears to be LIPA's recommendation to increase the Local Sourcing Requirement of the import-constrained area by the amount of the export at no cost to the exporter. To the extent that such capacity exports involve use of constrained transmission capacity, the exporter should pay a just and reasonable price for the transmission capacity.

Use of "As Is" versus "At Criterion" Standard

Protests

44. ISO-NE states that "as is" and "at criterion" are two ways of modeling neighboring areas to determine the tie benefits modeled in the ISO-NE Installed

[37] The Commission's decision here renders moot LIPA's request for a technical conference.

Capacity Requirements LOLE model. "As is" assumes that neighboring areas will have resources and demands equal to those forecasted for the capacity period. These forecasted resources and demands could be more or less than those needed to meet the reliability standard of 0.1 LOLE. "At criterion" assumes that neighboring areas will have enough resources so that each area separately meets the reliability standard of 0.1 LOLE based on forecasted load for the capacity period.

45. ISO-NE proposes to use "at criterion" for the 3-year ahead capacity period and "as is" for the reconfiguration auction 2 months prior to the capacity period. ISO-NE argues that "at criterion" assumptions are appropriate for the long-range planning associated with the 3-year-ahead auction because there is much less certainty that a capacity surplus or deficiency will exist in a neighboring area. By contrast, according to ISO-NE, since the reconfiguration auction will occur only two months before the Power Year, "as is" assumptions are likely to more accurately reflect the resources that will actually be available during the Power Year.

46. The NYSRC is concerned with ISO-NE's proposal to assume "as is" assumptions for capacity levels in neighboring control areas in the process of determining New England's annual ICR. The NYSRC argues that this modeling approach will result in unreasonably low New England ICR, diminish the reliability of neighboring control areas, such as New York, and would result in New York ratepayers

subsidizing New England. For example, NYSRC contends that modeling the New York control area under "as is" assumptions produces a capacity margin of approximately 30 percent rather than 16.5 percent design level for 2007. Finally, the NYSRC is concerned that the ISO-NE filing makes no reference to a Joint Tie Benefit study that has been undertaken jointly by the NYSRC/NYISO and ISO-NE, which includes an evaluation and determination of the level of emergency assistance that New York and New England can provide to one another. The NYSRC asserts that the Commission should direct ISO-NE to reconsider the use of the "as is" approach and to submit its proposal for discussion in the context of the Joint Tie Benefit study.

47. The NYSRC is equally concerned with ISO-NE's proposal to ignore firm export capacity commitments when determining ICR and locational requirements. The NYRSC states that the curtailment of firm capacity contracts is inconsistent with NYISO market rules and may jeopardize ISO-NE participation in the NYSIO market. The NYSRC argues that this issue should be resolved jointly as part of ongoing NYSRC/NYISO/ISO-NE Joint Tie Benefit study.

48. National Grid in its reply comments states that it is appropriate to use the "as is" measurement as the capacity period approaches because that approach more closely reflects the reality of the capacity available to New England from neighboring control areas, including both capacity excess and capacity shortages.

Commission Decision

49. We agree with ISO-NE that it is appropriate to use "as is" for the Annual Reconfiguration Auction two months before the Capacity Commitment period. This allows the reconfiguration auction to more accurately reflect the ICR needed to ensure that there is enough generation to reliably meet load in New England without overrelying on neighboring capacity and without overcharging New England customers for unnecessary capacity. We do not agree with NYSRC's argument that this will be detrimental to reliability in New York. As ISO-NE explained in its reply comments, the "as is" criterion will still limit tie benefits to the physical capacity of the tie lines minus firm capacity imports, and it only allows increased use of tie benefits to the extent that there is capacity available above the "at criterion" level in neighboring areas. In addition, we recognize that a new generator generally cannot be built within a two month period, so the "as is" criterion is reasonable for this short time period. By contrast, there is more uncertainty as to what generators will be built or retired in the three-year period where the "at criterion" assumption is used, and thus use of the "at criterion" assumption is a reasonable approximation of the expected capacity situations in neighboring areas for the 3-year forward auction.

50. We also agree with the ISO-NE that the Joint New England/New York reliability study is to provide guidance, and ISO-NE is not obligated to operate according to the assumptions of the study. We

recognize this as an important effort, and encourage the ISOs to continue to jointly study the impacts of their tie benefits assumptions.

Internal Constraints

Protests

51. Con Ed argues that the proposed ICR methodology ignores internal transmission constraints when calculating the level of tie benefits used to determine the overall system-wide ICR. Con Ed notes that in determining Local Sourcing Requirements, the proposed rules consider internal transmission constraints and argues that the same consideration should be made when determining the level of tie benefits. Con Ed argues that the proposed ICR rules ignore the possibility that the available resources may be constrained by internal transmission limits, and therefore unable to transmit their output to the necessary load centers. Con Ed further argues that this approach automatically assumes that there will be support available from the broader ISO-NE market and will produce an understated ICR. Finally, Con Ed contends that ISO-NE has conducted studies that clearly demonstrate that tie benefits are heavily dependent on internal transmission constraints.[38]

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[38] Con Ed states that in a 2003 presentation, ISO-NE indicated that summer tie benefits could range from 50 MW to

(Continued on following page)

52. In its answer, ISO-NE argues that the Commission should deny Con Ed's protest. ISO-NE asserts that Local Sourcing Requirements will be used to ensure that there is adequate capacity in import-constrained zones. ISO-NE states that during the calculation of Local Sourcing Requirements, tie benefits are assumed to accrue in the New England zone to which the interface interconnects. Thus, ISO-NE asserts, capacity is distributed in such a way to alleviate internal constraints.

Commission Decision

53. The Commission will not direct ISO-NE to revise its proposed approach to calculating the level of tie benefits at this time. Con Ed has raised this issue in previous proceedings in which ISO-NE has filed the annual ICR level. In the proceeding covering the 2006/2007 power year, Con Ed made substantially the same argument. In that proceeding, the Commission not only found that the resulting ICR level was just and reasonable, it did not direct ISO-NE to model internal constraints into the determination of tie benefits.[39] ISO-NE and NEPOOL assert that the proposed rules in the instant filing merely modify existing ICR processes in order to accommodate the FCM. Con Ed has not demonstrated

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nearly 3,000 MW, depending on the extent to which ISO-NE modeled constraints. *See* Con Ed protest at 6.

[39] *ISO New England, Inc.* 115 FERC ¶ 61,149 (2006).

why its requested approach to calculating tie benefits is required to accommodate the FCM, particularly given that the Commission has previously found that the approach embodied in the proposed rules has produced just and reasonable results.

Additional Issues raised by CT DPUC Protest

54. CT DPUC challenges a number of definitions and concepts contained in the ISO-NE/NEPOOL filing. The Commission's rulings on those challenges are below.

1. Definition of Existing Capacity Resource

55. Among the modifications to the ISO-NE tariff is the addition of a definition for an "Existing Capacity Resource" as :

> any resource that does not meet any of the eligibility criteria to participate in the forward Capacity Auction as a New Capacity Resource, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

56. The CT DPUC argues that the FCM Settlement Agreement provides that a new capacity resource

may elect to be treated as an Existing Capacity Resource. Thus, the CT DPUC asks that the proposed definition be revised to state that a new capacity resource may be required to be treated as an Existing Capacity Resource pursuant to contract requirements or for other reasons, and seeks the addition of the following language at the end of the last sentence above:

> . . . or that is not within 12 months of its requested commercial operations date but is required pursuant to contract or otherwise elects to be treated as an Existing Capacity Resource.[40]

57. In its answer, ISO-NE argues that the intent of the proposed definition is to allow a new capacity resource to be treated as an Existing Capacity Resource in the Forward Capacity Market, and additionally, that the forthcoming rules governing the operation of the Forward Capacity Market will provide a description of how a new capacity resource can be classified as an Existing Capacity Resource if it elects to do so as required contractually or otherwise.

58. The Commission finds that the definition proposed by the CT DPUC appears to reflect the intent of the FCM Settlement Agreement, and the definition provided by ISO-NE in its filing does not accomplish this purpose. Moreover, the Commission

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[40] CT DPUC protest at 13.

notes that ISO-NE and the CT DPUC appear to agree that the definition of an Existing Capacity Resource should reflect the idea that a new capacity resource may elect to be treated as an Existing Capacity Resource for contractual or other reasons. The Commission directs ISO-NE to revise the definition of an Existing Capacity Resource either as proposed by the CT DPUC or in such a way that it clearly articulates that a new capacity resource may elect to be treated as an Existing Capacity Resource. We will therefore require ISO-NE and NEPOOL to revise the definition of an Existing Capacity Resource, as discussed above, within 30 days of the date of this filing.

2. Definition of Permanent De-list Bid

59. Another modification to the ISO-NE tariff is the addition of a definition for a "Permanent De-list Bid." The proposed definition states that a Permanent De-list Bid "is a bid submitted in the Forward Capacity Auction by an Existing Capacity Resource to permanently de-list capacity." The CT DPUC asserts that the definition proposed in the instant filing is merely a tautology and provides no definition for permanently de-listed capacity. The CT DPUC argues that the FCM Settlement Agreement, at section 11.III.D.3, provides an accurate and useful definition and that the proposed definition should be modified to comport with the FCM Settlement Agreement.

60. In its answer, ISO-NE states that a detailed definition of Permanent De-list Bids will be provided in the FCM market rules, so the CT DPUC's request that the Commission order the ISO to adopt a more detailed definition of "Permanent De-List Capacity" should be denied.

61. The Commission agrees with the CT DPUC and finds that the definition as proposed by ISO-NE is insufficient. We further find that the language within the FCM Settlement Agreement provides for a fuller description of Permanent De-list Bids. While it may be true that ISO-NE will file a more detailed definition in a subsequent filing, that filing has not yet been presented to the Commission and, as such, we cannot rely on that subsequent filing in place of a fuller definition for the purposes of the proposed rule. We will therefore require ISO-NE and NEPOOL to provide a fuller description of Permanent De-list Bids, as discussed above, within 30 days of the date of this filing.

3. Modeling Capacity Zones Using "As is" Assumptions

62. As discussed above, the proposed rules in the instant filing describe the establishment of Local Sourcing Requirements, which identify the minimum number of MWs an import-constrained sub-region must procure in an FCM auction. The CT DPUC notes that none of the proposed rules in the instant filing expressly specifies that resources in the

import-constrained sub-regions and the rest of the New England control area will be modeled using "as is" assumptions. The CT DPUC states that its understanding is that, with regard to proposed section III.12.6, the use of "as is" assumptions is implicit, but it argues that the Commission should state that ISO-NE will use "as is" assumptions for the purposes of modeling all resources in all auctions, except for the modeling tie benefits for specified auctions. The CT DPUC asserts that the use of "at criterion" assumptions for resources in Connecticut and the rest of the New England control area could be extremely detrimental for Connecticut.

63. In its answer, ISO-NE states that there is no need for the requested clarification. ISO-NE notes that, under proposed section III.12.2 of the ICR Rules, all resources (pursuant to section III.12.7) will be included in the modeling assumptions for determining Local Sourcing Requirements. ISO-NE states that this includes all resources that are expected to be available plus additional units that may be needed to meet the LOLE criterion. ISO-NE argues that these provisions describe a calculation that is (as much as is possible more than three years in advance) an "as is" calculation based on the best estimate of resources that are expected to be available.

64. The Commission will not direct ISO-NE to make the requested changes. The Commission agrees with ISO-NE's answer and finds that the proposed rules reflect the use of "as is" assumptions in modeling

capacity zones. Section III.12.2.1 of the ICR Rules states that, for the purposes of calculating import-constrained zones, the load zone under study (as well as the rest of the New England control area) will include "all load and all resources electrically located within the zone."

4. Transmission Interface Limits

65. Section III.12.5 of the proposed rules states that:

> The transmission interface limits shall be established, using deterministic analyses, at levels that provide acceptable thermal, voltage and stability performance of the system both with all lines in service and after any criteria contingency occurs as specified in ISO New England Manuals and ISO New England Administrative Procedures.

66. The CT DPUC asserts that transmission interface limits are a crucial input for determining Local Sourcing Requirements and argues that material aspects of that analysis should not be relegated to ISO-NE's Manuals and Administrative Procedures. CT DPUC argues that the basis for ISO-NE's determination of interface limits, whether in the tariff or in manuals and administrative procedures, should be subject to Commission review and stakeholder challenge under section 205 of the FPA. Thus, the CT DPUC asserts, the Commission should clarify that any change to ISO-NE's manual or administrative procedures that affects its analysis of

transmission interface limits substantially affects rates and must be filed with the Commission under section 205.

67. In its answer, ISO-NE states that the CT DPUC's request should be denied. ISO-NE states that it will continue to make its annual ICR-values filings with the Commission. ISO-NE asserts that in establishing the ICR values, there will be a detailed review before stakeholders and the Commission of the various factual determinations reflected in the annual filing. Thus, ISO-NE concludes, any and all points of contention regarding the annual ICR filing, including the determination of transmission interface limits, can be addressed at that time.

68. The Commission will not direct ISO-NE to file changes to manuals or administrative procedures that affects analysis of transmission interface limits with the Commission under section 205. The Commission finds that, insofar as ISO-NE and stakeholders continue to develop and file with the Commission annual ICR values, the CT DPUC will have an opportunity to address transmission interface limits that are inputs into the determination of ICR values. Moreover, the Commission notes that the proposed rules provide for participation from state regulatory agencies in a portion of the ICR development process that affects transmission interface limits. Section III.12.5 of the proposed rules states that prior to each auction, ISO-NE will update transmission interface limits, accounting for "any additional transmission projects and elements of

transmission projects that are added to the network model." The proposed rules further state that during the process of making transmission infrastructure determinations to be included in the network model, ISO-NE will "consult with the Governance Participants, the Transmission Owners, any transmission project proponents, the state utility regulatory agencies in New England and, as appropriate, other state agencies." The Commission finds that the combination of the annual ICR filing and the opportunity for state regulatory agencies to participate in the process affords them sufficient opportunity to address any interface issues. Thus, a further filing is not required.

5. Establishing the Network Transmission Model

69. Section III.12.6.2 of the proposed rules lists the initial milestones that transmission projects must meet in order to be considered in service. ISO-NE will determine whether transmission projects or elements of transmission projects meet all of the following requirements:

a) A "critical path schedule" for the transmission project, provided to ISO-NE that shows that the transmission project will be in-service no later than the first day of the relevant capacity period;

b) At the time of review, siting and permitting processes, if required, are on schedule as shown on the critical path schedule;

c) At the time of review, engineering is on schedule as shown on the critical path schedule;

d) At the time of review, land acquisition, if required, is on schedule as shown on the critical path schedule;

e) Certification from a transmission company's officer that the schedule is achievable and the owner intends to build in accordance with that schedule; and

f) For a transmission project that meets the initial threshold milestones specified above, ISO-NE will consider the other factors and "any other relevant information" to determine whether to include the transmission project in the network model for a specific capacity period.

70. The CT DPUC asserts that these criteria are too rigid and may exclude transmission resources that will, in fact, be in place to reduce ICR or a Local Sourcing Requirement, which may result in customers being required to purchase a greater amount of capacity than is truly necessary. The CT DPUC is primarily concerned that criteria (b)-(d) could be used to exclude a transmission project from the network model based solely on immaterial deviations from its projected schedule. The CT DPUC argues that delays in siting, permitting, engineering, and land acquisition may not necessarily change a project's in-service date. Thus, the CT DPUC continues, in adopting an inflexible rule that automatically disqualifies projects from consideration if any of these activities are behind schedule, ISO-NE

would ignore the real impact delays in those activities may have on project completion.

71. Moreover, the CT DPUC asserts that in imposing an absolute set of criteria for including a transmission project in the network model, ISO-NE's proposed rule would disregard the significance of any schedule slippage and may not consider a project because of a very small delay that is insignificant for the overall project. The CT DPUC also contends that many projects have contingency plans, which allow them to recoup delays (*e.g.*, by adding extra workers or hours) and fulfill the project schedule. The CT DPUC states that ISO-NE's proposed rule would mechanically exclude any project that misses any milestone date without regard to its real consequences for the project. The CT DPUC asserts that section III.12.6.3 allows ISO-NE some flexibility in evaluating probable in-service dates and asks that the Commission to move factors (b)-(d) from to section III.12.6.3 so that ISO-NE can apply appropriate flexibility to assess whether a transmission project will be in-service by the start of the relevant capacity period.

72. In its answer, ISO-NE argues that threshold requirements in proposed section III.12.6.2 are not overly restrictive and that the CT DPUC's request should be denied. ISO-NE states that these criteria were carefully drafted so as to enable the ISO to ensure the accuracy of the in-service dates of the projects upon which its transmission network model will be based. Furthermore, ISO-NE contends that

were it to forecast a particular date and the transmission resource failed to be in place in time, system reliability could be severely imperiled. Finally, ISO-NE contends that, given that transmission projects lack the financial assurances of generation projects in the New England, it is even more necessary to subject such projects to a well-defined standard.

73. The Commission will not direct ISO-NE to modify its tariff as requested by the CT DPUC. The Commission finds that the proposed milestones identified in section III.12.6.2 represent reasonable and identifiable initial markers to determine whether a transmission project may be included in the network model. Moreover, the Commission finds that they provide adequate certainty with regard to creating the network model and thus the actual ICR. The Commission finds that relaxing the proposed milestones would only serve to add uncertainty to the model. The Commission further finds that the milestones articulated in the proposed rule are not restrictive. We believe that a record that shows that siting and permitting, engineering and land acquisition processes are on schedule provides ISO-NE with an appropriate set of thresholds by which to judge the progress of transmission projects.

6. Definition of "Capacity Zone"

74. The CT DPUC claims that the definition of "Capacity Zone" in section III.1.3 of Market Rule 1 is

potentially inconsistent with other parts of the proposed rules. Specifically, the CT DPUC notes that multiple sections[41] of the proposed rules each make the electrical location of a resource controlling, not its geographic location, as is asserted in the definition of "Capacity Zone." The CT DPUC therefore requests that the definition of "Capacity Zone" be changed to "an electrical sub-region of the New England Control Area, as determined in accordance with sections III.12.4 of this Market Rule."[42]

75. We disagree with the CT DPUC regarding the definition of "Capacity Zone." The CT DPUC is correct that the electrical location of a resource should be controlling in defining a Capacity Zone; however, Market Rule 1 already provides for an accurate definition of Capacity Zone. As ISO-NE points out in its Answer, proposed section III.12.4 of Market Rule 1 explains that Capacity Zones will be modeled as export-constrained, import-constrained and adjacent "Load Zones," which are defined as "Reliability Regions, except at otherwise provided for in section III.2.7 of this Market Rule."[43] "Reliability Regions" are regions "identified on [ISO-NE's] website. Reliability Regions are intended to reflect the operating characteristics of, and the major

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[41] See sections III.12.2, III.12.2.2.1(d), III.12.2.2(a), and III.12.7.3.

[42] CT DPUC protest at 13.

[43] ISO-NE's Answer at 36, *citing* section III.1.3 of Market Rule 1.

transmission constraints on, the New England Transmission System,"[44] *i.e.*, the electrical location of a resource is controlling. We therefore reject CT DPUC's requested definition of "Capacity Zone" as unnecessary.

7. Definition of "Loss of Load Expectation"

76. The CT DPUC protests ISO-NE's definition of "Loss of Load Expectation." Specifically, the CT DPUC claims that ISO-NE has provided an incomplete definition of the term that fails to convey the full scope of the Northeast Power Coordinating Council resources adequacy design criterion. As such, the CT DPUC requests that the definition of "Loss of Load Expectation" be revised to reflect the same definition provided by the Northeast Power Coordinating Council.

77. We disagree with the CT DPUC that the definition of "Loss of Load Expectation" should be expanded to reflect the Northeast Power Coordinating Council definition *verbatim*. The ICR Rule explains ISO-NE's method for calculating the ICR in relation to Loss of Load Expectation criterion and is more complicated than the Northeast Power Coordinating Council definition. ISO-NE's definition of "Loss of Load Expectation" serves the purpose of

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[44] *Id.* at 37, *citing* section III.1.3 of Market Rule 1.

the ICR Rule in explaining how ISO-NE has implemented the Loss of Load Expectation criterion. As such, it is unnecessary to require ISO-NE to conform its definition of "Loss of Load Expectation" to exactly match the Northeast Power Coordinating Council definition.

8. Calculation of Local Sourcing Requirements

78. The CT DPUC claims that in modeling external Control Area support from tie benefits, the proposed rule is not clear that Connecticut's Local Sourcing Requirement should reflect the locational tie benefits that accrue from the Cross Sound Cable and 1385 Cable. The CT DPUC claims that ISO-NE should clarify that the tie benefits attributable to the Cross Sound Cable and 1385 Cable are to be assigned to Connecticut in assessing the Connecticut's Local Sourcing Requirement, not to the entire New England region. The CT DPUC claims that the Cross Sound Cable and 1385 Cable provides a valuable reliability contribution to the Connecticut load zone specifically. The CT DPUC points out that the Initial Decision in *Devon Power*[45] recommended that ISO-NE "be required to calculate Connecticut's capacity

[45] *Devon Power LLC*, 111 FERC ¶ 63,063 (2005) (*Devon Power* Initial Decision).

transfer limits to reflect the reliability benefits provided by the Cross Sound and 1385 Cables."[46]

79. The Commission finds CT DPUC's requested clarification unnecessary. The ICR Rule already provides for the inclusion of tie benefits on the import-constrained side of the interface in the calculation of Local Sourcing Requirements, if any such tie benefits exist.[47] The proposed revisions to the ICR Rule further require ISO-NE to engage in a study of tie benefits at least once every three years, and the results of the study must be updated if conditions in the New England Control Area or neighboring Control Areas change.[48] We find the existing ICR Rules and the proposed changes to the ICR Rules sufficient to appropriately apply all applicable tie benefits attributed to the Cross Sound Cable or 1385 Cable in calculating Connecticut's Local Sourcing Requirement.

80. The CT DPUC also specifically requests that the Commission ensures that all tie benefits from the Cross Sound Cable and the 1385 Cable be applied solely to the calculation of Connecticut's Local Sourcing Requirement and not be considered a regional benefit to be applied to the entire New England region.

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[46] CT DPUC Protest at 15, *citing Devon Power* Initial Decision at P 743.

[47] Section III.12.2.1 of Market Rule 1.

[48] Proposed section III.12.9 of Market Rule 1.

81. The Commission denies the CT DPUC's request for this ruling. First, a showing has yet to be made that the Cross Sound Cable and/or 1385 Cable provides a unique reliability benefit to the New England Control Area or the Connecticut Load Zone. While the Cross Sound Cable and 1385 Cable do provide transmission between New England/ Connecticut and Long Island, capacity benefits of that tie can only accrue to New England if Long Island has an ample surplus of capacity. As explained by ISO-NE in its Answer, the New York ISO currently requires Long Island to satisfy 99 percent of its peak installed capacity requirements with local resources which leaves Long Island with only "marginal excess."[49] Long Island's thin capacity margin, combined with the lack of evidence that New England/Connecticut has enjoyed a unique reliability benefit from the Cross Sound Cable and/or the 1385 Cable, removes any base for specifically assigning tie benefits to the Connecticut Load Zone uniquely attributable to the Cross Sound Cable and/or 1385 Cable.

82. The Commission has consistently found that the Cross Sound Cable, in particular, has not been shown to provide any unique capacity reliability benefit to the New England Control Area. In the 2005 order accepting ISO-NE's ICR for the 2005/2006 power

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[49] ISO-NE Answer at 24, citing testimony of LIPA witness Bolbrock in *Devon Power LLC*, Docket No. ER03-563-030, Tr. at 3791:19-25.

year,[50] the Commission found that ISO-NE's study supported tie line benefits of 2000 MW for the 2005/2006 Power Year.[51] However, the Commission did not attribute any part of that 2000 MW tie benefit to a specific Load Zone; rather, the tie benefit was assigned to the entire New England region and the benefit itself was calculated considering all ties with the New York Control Area.

83. In the order on rehearing of the 2005 ICR Order, the Commission stated that "there is nothing in the record that indicates that any portion of the 600 MW tie line benefit assigned to [the New York Control Area] that was included in the February 2003 Tie Reliability Benefits Study was attributable to the Cross Sound Cable."[52]

84. The CT DPUC's reliance on the *Devon Power* Initial Decision in support of its position on tie benefits from the Cross Sound Cable and 1385 Cable is misplaced. In the *Devon Power* Initial Decision, the administrative law judge "recommend[ed] that the Commission direct the ISO to recalculate [capacity transfer limits] for [Connecticut] to reflect the

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[50] *See ISO New England, Inc.*, 111 FERC ¶ 61,185 (2005 ICR Order), *reh'g. denied*, 112 FERC ¶ 61,254, (2005), *appeal pending sub nom. Connecticut Department of Public Utility Control* v. *Federal Energy Regulatory Commission (CT DPUC)*, U.S.C.A., D.C. Circuit, Docket No. 05-1411.

[51] 2005 ICR Order at P 30.

[52] 112 FERC ¶ 61,254 at P 14.

reliability benefits provided by the cables."[53] This recommendation was grounded in the assumption that the ICR values established in the 2005 ICR Order ascribed tie benefits to the Cross Sound Cable and 1385 Cable. In fact, the 2005 ICR Order made no such finding. At no point in that order did ISO-NE determine tie benefits attributable to the Cross Sound Cable or the 1385 Cable, and at no point did the Commission accept such an assertion. Rather, the 2005 ICR Order accepted tie benefits attributable to all ties between the New York Control Area and the New England Control Area. The administrative law judge's recommendation in the *Devon Power* Initial Decision on which the CT DPUC seeks to rely, therefore, was based on an erroneous assumption that the Cross Sound Cable and 1385 Cable provide specific reliability benefits to Connecticut,[54] rather than making a specific finding in that regard, as CT DPUC implies.

9. Determination of Capacity Zones

85. The CT DPUC asserts that section III.12.4(b) of the proposed ICR Rules will incorrectly establish the total amount of projected installed capacity that will

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[53] *Devon Power* Initial Decision at P 743.

[54] The *Devon Power* case was ultimately resolved through a settlement which did not address the specific contentions of P 743; *see* FCM Orders.

be available at the start of the Capacity Commitment Period and does not reflect the terms of the FCM Settlement Agreement. Specifically, the CT DPUC claims that ISO-NE has failed to include Intermittent Resources and New Capacity Resources that are "on track for completion by the start of the first Capacity Commitment Period."[55] The CT DPUC claims that the FCM Settlement Agreement recognized the need for special rules in the ICR methodology applicable to Intermittent Resources.[56] The CT DPUC also claims that proposed section III.12.7.2 of the ICR Rules should be revised to include all resources, including Intermittent Resources and New Capacity Resources, that are expected to be in service by the first day of the relevant Capacity Commitment Period.

86. The CT DPUC's assertion that Intermittent Resources are not considered in the assessment of project installed capacity is unfounded. As ISO-NE points out in its Answer, Intermittent Resources are considered to be "Resources," as defined in Market Rule 1. A "Resource" is defined in Market Rule 1 as, among other things, "a generating unit;"[57] this definition includes Intermittent Resources. As such, all generating units, including Intermittent Resources, will be included in ISO-NE's assessment of projected installed capacity. It is therefore

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[55] CT DPUC Protest at 19.

[56] *Id.* citing FCM Settlement Agreement, section 11.II.E.1.a.

[57] Section III.1.3 of Market Rule 1.

unnecessary to require ISO-NE to alter proposed Rule III.12.4(b) as requested by the CT DPUC.

87. The CT DPUC's claim that ISO-NE failed to comply with the FCM Settlement Agreement's requirement to include New Capacity Resources qualified by ISO-NE for the FCM that are on track to be completed by the start of the first Capacity Commitment Period in the calculation of ICR is also baseless. The proposed ICR Rules dictate that all Existing Capacity Resources will be included in the calculation of ICR. "Existing Capacity Resources" includes resources that are under construction and within 12 months of the expected commercial operations date, subject to review by ISO-NE.[58] Thus, those new resources that are within 12 months of commencement of expected commercial operations will be treated as Existing Capacity Resources for the first Capacity Commitment Period.

88. We also disagree with CT DPUC's requested modification of proposed Rule III.12.7.2 to include all Intermittent Resources and New Capacity Resources that qualify for the FCM in the calculation of ICR. As explained above, Intermittent Resources are considered "Resources" and so will be included in the ICR calculation. New Capacity Resources, however, are resources that do not yet have an obligation to commence operations by the start date of the relevant Capacity Commitment Period; rather, these resources

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[58] *Id.*

have simply made a show of interest. ISO-NE should not rely on resources that have yet to receive an obligation to provide capacity by clearing in an auction in calculating ICR. Doing so would introduce an unnecessary risk of overstating the actual reliability of the New England system by assuming a level of capacity supply that may not all be operational at the start of the Capacity Commitment Period. ISO-NE's proposed ICR Rule appropriately adopts a more conservative and reliable approach by including only those resources that have an obligation to provide capacity in the relevant Capacity Commitment Period. The CT DPUC's request for modification is therefore rejected.

10. Generation Modeling Assumptions

89. The CT DPUC protests ISO-NE's proposal to include in its network model only those new generating units that have

> a valid Interconnection Request for which a draft Interconnection Feasibility Study report has been submitted to the Interconnection Customer and is reasonably expected to declare commercial operation no later than the first day of the relevant Capacity Commitment Period whether or not

such unit is participating in the Forward Capacity Market qualification process.[59]

90. The CT DPUC claims that ISO-NE's completion of a draft Interconnection Feasibility Study report is not a relevant criterion for determining whether a new resource will be in service by the start of a Capacity Commitment Period. The CT DPUC argues that ISO-NE's proposed Generation Modeling Assumptions will require a new generating resource to submit an Interconnection Request about four and a half years before the relevant Capacity Commitment Period in order to be included in ISO-NE's network model. The CT DPUC claims that many new generating units and capacity additions to existing facilities have a much shorter lead time and could not be reasonably expected to submit Interconnection Requests so far in advance.

91. The CT DPUC also argues that the requirement for a draft Interconnection Feasibility Study so far in advance of the Capacity Commitment Period may be inconsistent with the qualification criteria for the FCA since the FCA qualification rules do not require an Interconnection Request or Interconnection Feasibility Study.

92. The CT DPUC therefore asserts that the only relevant basis for determining whether a generating resource is expected to be in service for a Capacity

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[59] Proposed section III.12.6(a)iii of Market Rule 1.

Commitment Period should be qualification for the FCA, *i.e.*, if a unit has met the qualification requirements for the FCA, it should be included in ISO-NE's network model for purposes of determining ICR and Local Sourcing Requirements.

93. The CT DPUC's interpretation of the network model generated by proposed section III.12.6(a)iii of the ICR Rules seems to be based on a misunderstanding of the purpose of the network model. As ISO-NE explains in its Answer, the purpose of this portion of the ICR Rules is to set transfer limits and handle interconnection requests, not to determine which units are assumed to be available to meet a Local Sourcing Requirement. ISO-NE will address this issue in its forthcoming FCM rules filing.

94. Further, a draft Feasibility Study is necessary in order to produce an accurate network model. As ISO-NE explains in its Answer, a network model is essentially an electronic representation of the transmission system, including all transmission lines, breakers, and substations. Interconnections potentially alter the network model, depending on if any new equipment is added to the system, *e.g.*, additional breakers. These material changes to the transmission system may affect transfer limits and/or the feasibility of other interconnection projects. Only a draft Interconnection Feasibility Study conveys any material modifications to the transmission system as a result of a new generating unit's interconnection. Without that information, ISO-NE will be unable to accurately generate a network model. We will

therefore reject the CT DPUC's request for modification of the proposed Generation Modeling Assumptions section of the ICR Rules.

11. Tie Benefits Study

95. The CT DPUC requests that the Commission require ISO-NE to perform a new tie benefits study if there is a change to the Northeast Power Coordinating Council-area electrical system that may materially affect tie benefits in the New England Control Area.

96. The proposed ICR Rules already provide for the relief the CT DPUC is requesting. Under the proposed ICR Rules, ISO-NE must update its tie benefits study if ISO-NE "determines that New England Control Area or external Control Area system conditions may change the results from the study."[60] As such, we will reject the CT DPUC's requested modification as unnecessary.

The Commission orders:

(A) The Commission hereby accepts the filing, with the modifications discussed above.

(B) The Commisison [sic] hereby requires ISO-NE file to propose a process for such exports as LIPA's export of capacity from Bear Swamp, *supra*, or explain why that established by the proposed rules in

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[60] Proposed section III.12.9 of Market Rule 1.

the instant filing and the subsequent FCM rules would address LIPA's concerns, within 180 days of the date of this order.

(C) The Commission hereby requires ISO-NE and NEPOOL to revise the definition of an Existing Capacity Resource, and to provide a fuller description of Permanent De-list Bids, as discussed above, within 30 days of the date of this filing.

By the Commission.

(SEAL)

Magalie R. Salas,
Secretary.

APPENDIX D

120 FERC 61,234
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners:	Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

ISO New England, Inc. and New England Power Pool — Docket No. ER07-365-002

ORDER DENYING REHEARING

(Issued September 14, 2007)

1. In this order, the Commission denies rehearing of an earlier order[1] accepting proposed tariff changes to revise ISO New England, Inc.'s (ISO-NE's) Market Rule 1 regarding the determination of the Installed Capacity Requirements (ICR) for the New England Control Area.

Background

2. ISO-NE is in the process of developing a forward capacity market (FCM), pursuant to a settlement agreement approved by the Commission in 2006.[2] In

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[1] *ISO New England, Inc.*, 118 FERC ¶ 61,157 (2007) (February 28 Order).

[2] *See Devon Power, LLC*, 115 FERC ¶ 61,340 (FCM Order), *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006) (FCM Order on Rehearing).

order to accommodate the FCM Settlement, ISO-NE and the New England Power Pool Participants Committee (NEPOOL) have revised portions of the process for developing ISO-NE's ICR.

3. The ICR is a projection of the minimum amount of capacity required to serve load reliably in the New England region at all times. ISO-NE determines the system's total ICR for each year, in accordance with existing resource planning reliability criteria. The ICR is expressed as the total number of MW that New England's Load Serving Entities (LSEs) will be required to purchase through the Forward Capacity Auctions. Once an ICR number is determined for each year, that number is then subdivided to arrive at the amount of MW of capacity that each LSE must purchase for that year.

4. The ICR directly affects the determination of the clearing price in the capacity market and so directly affects charges to customers. During the Forward Capacity Auction, which is a so-called "descending clock" auction, all capacity resources submit supply offers at descending price levels, beginning at a price equal to twice the Cost of New Entry (CONE).[3] As the auction price decreases, the amount of supply offered by capacity resources will naturally decline. The

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[3] The Cost of New Entry for all capacity zones in the first Forward Capacity Auction will be $7.50/kW-month. Cost of New Entry values for subsequent Forward Capacity Auctions will be calculated based on the clearing prices from previous successful auctions.

auction ends when the amount of capacity offered by New England capacity resources equals the ICR. The price at which the amount of capacity offered (i.e., the supply) equals the ICR (i.e., the demand) is the market clearing price for that auction. Thus, the ICR directly affects charges to customers.

5. Pursuant to section 205 of the Federal Power Act (FPA), on December 22, 2006, ISO-NE and NEPOOL jointly submitted proposed revisions to the ISO-NE tariff that are designed to memorialize the processes and methodologies used to determine the ICR, which previously had not been memorialized in the tariff.

6. In its February 28 Order, the Commission accepted ISO-NE's and NEPOOL's filing. The Connecticut Department of Public Utility Control (CT DPUC) and the Long Island Power Authority (LIPA) have filed timely requests for rehearing. NEPOOL filed a motion for leave to file an answer and answer to the CT DPUC's request for rehearing, and the CT DPUC filed a response in opposition to NEPOOL's motion and answer.

Discussion

7. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2007), prohibits an answer to a request for rehearing. We therefore reject NEPOOL's answer and dismiss the CT DPUC's response.

8. As discussed below, the Commission denies both requests for rehearing.

Jurisdiction

9. In the February 28 Order, the Commission found that it has jurisdiction to consider the proposed mechanism for the determination of ICR. We pointed out that, as we had previously stated in our order accepting the parties' settlement regarding the FCM, the FCM "establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce,"[4] and the FCM was therefore within our jurisdiction.

10. We further found that the determination of the ICR is one of the principal determinants of the price of capacity, and so it falls within the Commission's jurisdiction to review, as the Commission is charged with review of "any rate, charge or classification" charged by a public utility for electric transmission or sales subject to Commission jurisdiction, and "any rule, regulation, practice, or contract affecting such rate, charge or classification."[5] We also found that this determination was consistent with prior court

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[4] February 28 Order at P 15, *citing FCM* Order at P 201.

[5] 16 U.S.C. § 824e(a) (2000).

decisions regarding the Commission's jurisdiction over capacity requirements and charges.[6]

11. We also stated that this view was consistent with the Commission's recent order conditionally accepting the market redesign for the California Independent System Operator Corporation (CAISO),[7] in which we found that the Commission properly considered resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory:

> [W]here an interconnected transmission system is operated on a regional basis as part of an organized market for electricity . . . all users of the system are interdependent, particularly with respect to reliability, i.e., one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource

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[6] *Municipalities of Groton* v. *FERC* (*Municipalities of Groton*), 587 F.2d 1296, 1302 (D.C. Cir. 1978); *Mississippi Industries* v. *FERC*, 808 F.2d 1525, 1542, *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1978).

[7] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1113 (2006) (CAISO Order), *order on reh'g*, 119 FERC ¶ 61,076 (2007) (CAISO Rehearing Order).

adequacy in determining whether rates remain just and reasonable and not unduly discriminatory.[8]

12. We then found that in New England, similarly, the ICR requirement was "an integral component of the charges that ISO-NE makes to its member LSEs,"[9] and that because ISO-NE will determine a single ICR requirement for its entire system (later to be subdivided among its LSEs), the Commission was required to review ISO-NE's ICR methodology to ensure that these charges are determined in a just and reasonable manner.[10] Further, we found that the bid caps in ISO-NE's energy markets would harm customers by discouraging construction of new capacity, absent an affirmative mechanism to elicit the construction of new supply.[11]

13. We stated that, contrary to arguments made by the CT DPUC, the Commission was asserting

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[8] CAISO Order at P 1113, *citing Cal. Indep. Sys. Operator Corp.*, 115 FERC ¶ 61,172 at P 36 (2006), and *Gainesville Utils. Dep't* v. *Fla. Power Corp.*, 402 U.S. 515, 529 (1971) (Commission has "responsibility to the public to assure reliable efficient electric service").

[9] February 28 Order at P 19. We pointed out that this fact had also been acknowledged by the CT DPUC, which stated that "ICR plays a pivotal role under the FCM Settlement in determining how much capacity New England's electric customers must procure." *Id.* at P 19 n. 21, *citing* CT DPUC protest at 4.

[10] *Id.* at P 19

[11] *Id.*, *citing* CAISO Order at P 1114.

jurisdiction not over generating facilities, but over "an essential component of the charge for wholesale capacity in interstate commerce,"[12] and that we were not requiring that any state build generation, or that any participant satisfy its capacity obligation via a particular resource.

14. Finally, we stated that our responsibility to assure that wholesale rates are just and reasonable does not mean that we cannot, when appropriate, accept state determinations regarding resource adequacy requirements, noting that in the CAISO proceeding we had found that we could, in appropriate circumstances, defer to state and local regulatory authorities to set resource requirements. We also pointed out, however, that there was currently no proposal from all the New England states for us to consider.

15. Thus, we stated, "we therefore act today to establish an integral component of the jurisdictional charge for wholesale capacity within New England to ensure that wholesale rates are just, reasonable and not unduly discriminatory."[13]

CT DPUC's request for rehearing

16. In its request for rehearing, the CT DPUC asserts that the Commission erred in approving the

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[12] February 28 Order at P 20.

[13] *Id.* at P 21.

ICR, on the basis that the FPA reserves to the states "jurisdiction over facilities used for generating electricity and resource adequacy decisions,"[14] and that, by establishing mechanisms and procedures to set ICR and approving ISO-NE's proposed market rules relating to ICR, the Commission exceeded its statutory authority.

17. The CT DPUC notes that it has consistently opposed the Commission's assertion of jurisdiction to set the amount of generating capacity necessary to meet ISO-NE's reliability requirements. It then notes, however, that the FCM itself does not set prices, and that it in fact "decoupled capacity price from ICR,"[15] since under the FCM capacity prices will be set by the competitive cost of new entry regardless of the amount of ICR. The CT DPUC states that the Commission acknowledged that, under the FCM, the amount of capacity required would not affect or control the capacity price.[16]

18. As explained in the greater detail below, the CT DPUC states that the Commission erred, in the February 28 Order, by:

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[14] CT DPUC request for rehearing at 1.

[15] *Id.* at 3.

[16] *Id.* at 3, *citing* FCM Order at P 201. The CT DPUC is presumably referring to the Commission's statement that "[t]he settlement does not in any way alter the method by which resource adequacy requirements (particularly the installed capacity requirement) are determined or direct that a particular amount of capacity be installed."

1) Inappropriately usurping the responsibility and authority of the New England states to establish resource adequacy standards, and exercising jurisdiction to set ICR on the basis that resource adequacy plays an important role in addressing whether Commission-jurisdictional wholesale prices reflect the exercise of market power or the scarcity of supply;

2) Incorrectly concluding that ISO-NE's mechanism to determine that ICR is a "practice . . . affecting" a wholesale capacity rate, charge or classification in New England and thus falls within the Commission's jurisdiction; and misapplying case law to arrive at this determination;

3) Incorrectly concluding that to allow the New England states to set ICR for use in the FCM could create situations where one party's resource adequacy decisions create reliability cost impacts on other participants in a regionally operated system; and

4) Incorrectly treating New England states differently from other states or regions by refusing to defer to the states' determinations regarding resource adequacy, and refusing state proposals to establish a mechanism for setting resource adequacy requirements.

19. The CT DPUC argues that the FPA grants jurisdiction over generating facilities and resource adequacy determinations, which the CT DPUC equates with the ability to set ICR, to the states, and that Congress did not change that jurisdictional allocation even if the ICR affects wholesale capacity rates or charges in some way. The CT DPUC also argues that, contrary to the Commission's claims, judicial precedent does not support Commission jurisdiction to set the amount of installed capacity resources that a state or region must have, and that no legitimate concerns about reliability impacts on other participants, market power, or scarcity of supply justify the Commission's usurpation of states' authority to set the level of ICR in New England. Finally, the CT DPUC states that, although the Commission has stated that it would defer to the states to establish resource adequacy requirements, it has refused to do so in New England, even when the states proposed specific alternative procedures.

20. As explained below, we deny the CT DPUC's request for rehearing, and affirm that we have jurisdiction to approve ISO-NE's rules for determining ICR. We address each of the CT DPUC's contentions in turn.

Commission Jurisdiction Under the FPA

CT DPUC argument

21. According to the CT DPUC, the FPA makes clear that states retain their traditional authority over the

determination of resource adequacy requirements, particularly when that determination bears directly on the amount of generating facilities that a state must provide. The CT DPUC states that Congress recognized that states are particularly well suited to evaluate the need for additional capacity resources and to determine the conditions for satisfying that demand and that Congress emphasized that federal regulation "extend[s] only to those matters which are not subject to regulation by the States."[17] The CT DPUC argues that this Congressional declaration should be respected. It also asserts that states have long regulated all aspects of resource adequacy and generating facilities, and there is no basis in the FPA or otherwise for disrupting this Congressionally-dictated allocation of responsibility.[18] The CT DPUC

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[17] CT DPUC request for rehearing at 9, *citing* 16 U.S.C. § 824(a) (2000).

[18] According to the CT DPUC, Congress reiterated this reservation of authority to the states in: section 201(b)(1), stating that "[t]he Commission shall have jurisdiction over all facilities for [the transmission of electric energy in interstate commerce] or [the sale of electric energy at wholesale in interstate commerce], but shall not have jurisdiction, except as specifically provided in this Part and the Part next following, over facilities used for the generation of electric energy . . . ;" in section 207, stating that even when a state commission complains about inadequate or insufficient interstate service, "the Commission shall have no authority to compel the enlargement of generating facilities" for the purpose of furnishing "proper, adequate, or sufficient service;" and section 215, which reiterated that the Commission's authority to set reliability standards "does not include any requirement to . . . construct new . . . generation capacity."

then states that the New England states themselves have developed resource adequacy plans for their utilities using the same reliability standards as the Commission (and thus producing, in the aggregate, a region-wide ICR); thus, the CT DPUC argues that there can be more than one technically acceptable solution to the question of how much capacity the New England region should purchase, and states' exercise of their authority to set resource adequacy levels will not interfere with any Commission goals.

22. The CT DPUC disputes the Commission's statement that, by setting ICR, it "is not asserting jurisdiction over generating facilities." It points to the fact that the majority of ISO-NE's capacity resources are generating facilities rather than demand response or other resources.[19] The CT DPUC considers irrelevant the Commission's argument that a state can satisfy its capacity obligation in many ways, when virtually all of those methods result in the necessity for a specified quantity of generating facilities that must be available within the state or region. It also

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[19] The CT DPUC states that ISO-NE's most recent assessment of available capacity resources in New England found 30,526 MW of summer capacity consisting of combined cycle, fossil, nuclear, hydro, jet, and diesel generating facilities, and only 580 MW of demand response. CT DPUC request for rehearing at 11, *citing* ISO-NE's "Preliminary 2007-2008 Installed Capacity Requirements Values," Agenda Item 2.0, PSPC Meeting No. 224, Jan. 26, 2007, available at http://www.isone.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2007/jan262007/draft_icr0708_01_23_2006.pdf at 10, 14, 17.

states that, as load grows, the only resources that can provide incremental kilowatt hours of energy are generators.

23. The CT DPUC argues that the most fundamental aspect of a state's jurisdiction over generating facilities is its authority to determine how much generating capacity is required, which decision has ramifications for all other aspects of state regulation and control over generating facilities. As an example, the CT DPUC argues that, because optimal locations for generating facilities – e.g., with the requisite access to fuel, water, transmission, and proximity to load – are scarce, if the Commission sets ICR at a level above what a state believes is necessary for reliability, that state may be required to (a) identify and approve additional sites where generation can be built, even if they are unsuitable or do not comport with the state's overall land use plans, (b) grant clean air waivers, (c) keep environmentally hazardous or undesirable units in service when they should be retired, or (d) forego the development of longer lead time, base load generating facilities – e.g., a new nuclear power plant – because it must instead add a succession of new peaking units each year to satisfy the annual ICR. The CT DPUC argues that, when the Commission sanctions ISO-NE's mechanism to set the level of ICR, it compels states to supply ISO-NE's projection of the minimum amount of capacity necessary to reliably serve load, and under the FCM, LSEs in each state must acquire their proportionate share of ICR at the Forward Capacity Auction

clearing price. Thus, the CT DPUC argues, the Commission's approval of ICR also dictates the amount of capacity that must be installed in each capacity zone. The CT DPUC states that "[b]y setting ICR, the Commission effectively strips the states of their FPA-protected control over generating facilities within their borders."[20]

24. The CT DPUC further argues that the Commission erred in its assertion that the ICR is one of the principal determinants of the price of capacity. It states that the FCM provides that the Capacity Clearing Price will be set by new capacity, not existing capacity, that the Commission has taken pains to distinguish between the mechanism for setting ICR and the mechanism for setting the capacity price, and that in the FCM, the ICR is "no more than a plug-in number in the rate formula."[21] The CT DPUC states that while the FCM requires load serving entities to purchase their proportionate share of ICR, how the ICR is set or by whom are not integral parts of the FCM, and the only role that the ICR has in the capacity charge is to provide the quantity multiplier in computing the total amount that load serving entities pay.

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[20] CT DPUC request for rehearing at 12.

[21] *Id.* at 14.

Commission Ruling

25. At the outset, it is important to note that section 201(b)(1) of the FPA confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and sales of electric energy at wholesale in interstate commerce.[22] Further, FPA section 205(a) states that:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.[23]

26. Thus, the FPA confers upon the Commission the responsibility for ensuring that transmission and wholesale power sales rates and charges, including any rule, regulation, practice or contract affecting them, are just and reasonable and not unduly discriminatory or preferential. And, given that the ICR is one of the principal determinants of the price

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[22] 16 U.S.C. § 824(b)(1) (2000).

[23] 16 U.S.C. § 824d(a) (2000). FPA section 206 similarly gives the Commission the ability to review "any rate, charges, or classification" charged by a public utility for any transmission or sale subject to the jurisdiction of the Commission, as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification. . . ." 16 U.S.C. § 824e(a) (2000).

of capacity and thus of charges to customers, review of the determination of the ICR rests with the Commission. In this regard, as described above, the ICR directly affects the capacity clearing price and charges to customers. The purpose of the Forward Capacity Auction is to determine the price at which the amount of capacity offered by all New England capacity resources equals the ICR (i.e., equals what is essentially demand); that price becomes the price of capacity, which, in turn, is charged to customers. The "stopping point" of this "descending clock" auction is therefore directly influenced by the size of the ICR (i.e., essentially demand): a greater ICR (i.e., essentially greater demand) will typically result in a higher price of capacity (i.e., a higher clearing price) and higher charges to customers, while a lesser ICR (i.e., essentially lesser demand) will typically result in a lower price of capacity (i.e., a lower clearing price) and lower charges to customers.

27. Turning to the specifics of the CT DPUC's arguments, as the CT DPUC states, in the FPA, Congress did not grant the Commission authority over electrical generating capacity. Contrary to the CT DPUC's claim, however, the Commission is not exercising authority over electrical generating capacity or setting the amount of generating capacity that states must build (or require to be built). Rather, the Commission is reviewing the means by which ISO-NE determines the amount of resources member LSEs must provide (which leads ultimately to a determination of the amount of resources each individual

state's LSEs must provide), which, as described above, directly affects the charges to customer, in order to evaluate the justness and reasonableness of the rates and charges to customers.

28. It is also critical to distinguish between ISO-NE's "capacity" requirement and "electrical generating capacity." In essence, "capacity" (the ability to produce electric energy to serve load, when called by ISO-NE) is the product, and electrical generating capacity is one means, but not the only means, of producing that product. For example, assume that within a particular state, ISO-NE determines that an LSE must provide 100 MW of capacity (in addition to the capacity that the LSE currently has). This does not mean that the LSE must necessarily construct, and the state must permit the construction of, 100 MW of new electrical generating capacity. The LSE could fulfill its capacity obligation to ISO-NE by constructing new electrical generating capacity but it could also add 50 MW of demand response[24] and 50 MW of capacity contracts (from inside or outside the state), or any mix of the above. If a state wishes to place controls on the amount or type of electrical generating capacity built within that state, or at particular locations within that state, the Commission's regulation of ISO-NE's calculation of ICR does

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[24] Demand response reduces load to be served, so that less electrical generating capacity is needed to serve load.

not prevent it from doing so.[25] The capacity requirement that ISO-NE places on an individual LSE may be a factor in a state's ultimate determination as to how much electrical generating capacity is built, and where and by whom. These are not, however, the same determinations, and it is inaccurate to conflate the two as the CT DPUC does here.

29. While, as the CT DPUC notes, currently the majority of the New England states' capacity needs are met through electrical generating capacity, this does not mean that that will remain the case in the future. The FCM is, in fact, currently eliciting the development of new resources, which may be electrical generating capacity or demand response providers.[26] Nothing in the ICR requirement prevents

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[25] *See, e.g., Jersey Central Power & Light Company* v. *Atlantic City Electric Co.*, 111 FERC ¶ 61,179 at P 10, 24-25, 27, *order on reh'g*, 113 FERC ¶ 61,237 at P 6-7, 47-48, 54-58 (2005), *reh'g denied*, 116 FERC ¶ 61,256 at P 13-15 (2006) (complainant sought relief from Commission-jurisdictional contract obligation to build facilities on the basis that, among other reasons, environmental regulation by the State of New Jersey prevented it from fulfilling its contract obligation; Commission responded that contract already contemplated that facilities might not be built and already provided complainant with options such as construction of other facilities).

[26] The fact that there has been significant interest in providing demand response service can be seen in *ISO New England, Inc.*, 119 FERC ¶ 61,045 (2007), where the Commission required changes to the FCM market rules in response to issues raised by multiple demand response providers to allow them to compete more effectively with electrical generating capacity. *See Id.* at P 145-147, 152.

a state from requiring its LSEs to meet capacity requirements through demand response, or through contracts to purchase power (from resources located inside or outside the state), or through more environmentally-friendly generation, or, generally speaking, through resources that meet state health or environmental or land-use planning goals. In essence, ISO-NE says to its LSEs, "Provide X amount of resources." But *how* those resources are provided is up to the LSEs and the states.

30. It is, moreover, inaccurate to state, as the CT DPUC does, that the FCM has "decoupled" price and capacity, and that the only effect that the ICR will have on capacity prices will be to provide the number of MW of capacity that LSEs acquire. Again, as explained above, the ICR has a direct impact on the capacity clearing price in the Forward Capacity Auction. And while it is true that the price of capacity will be set by the CONE in those circumstances in which new entry is needed to meet capacity requirements,[27] ISO-NE's ruling of how many MW of capacity each LSE must acquire will determine whether, in fact, new resources will need to be developed to enable LSEs to meet that standard.

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[27] As described above, in the Forward Capacity Auction all capacity resources submit supply offers at descending price levels, beginning at a price equal to twice the CONE. Where new entry is needed to meet capacity requirements, though, as the cost of new entry is the CONE, the price of capacity will be set by the CONE.

Further, even in situations where new capacity resources are developed and set the per-MW price, an LSE's total cost for capacity will be the result of (a) the price of each MW, multiplied by (b) the number of MW the LSE must purchase.

Relevant Caselaw

CT DPUC argument

31. The CT DPUC also states that, in *Northwest Central Pipeline Corp.* v. *State Corp. Comm'n of Kansas*,[28] the Supreme Court found that a practice that merely "affects" rates or charges does not negate the FPA's reservation of jurisdiction over resource adequacy to the states, unless state determination of resource adequacy would prevent attainment of Commission goals – a showing that, the CT DPUC argues, the Commission has not made here. According to the CT DPUC, Congress did not intend that any practice "affecting" rates and charges trumped the reservation of jurisdiction to the states. Rather, the CT DPUC argues, in *Northwest Central* the Court found that, although almost any state regulation of generating facilities could have an impact on wholesale capacity costs, "Congress has drawn a brighter line, and one considerably more favorable to the States' retention of their traditional powers to regulate" the facilities that produce electric

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[28] 489 U.S. 493 (1989) (*Northwest Central*).

energy.[29] Thus, the CT DPUC states, state regulation of generating facilities may be pre-empted only if "state regulation prevents attainment of FERC's goals,"[30] and the Commission has not made such a showing.

32. The CT DPUC argues that the Commission's reliance on *Groton* and *Mississippi Industries*[31] is inapposite. It asserts that *Groton* did not involve a Commission order relating to generating facilities, but rather, the rate that would be charged for a capacity deficiency, and that in *Mississippi Industries* the Commission only acted to remedy discrimination in the allocation of existing capacity costs, but not to establish the amount of capacity that a system would have to acquire. The CT DPUC considers it impermissible to "leap" from such authority over cost allocation to requiring the provision of a particular amount of capacity, since setting ICR is a reliability and resource adequacy question, not a cost allocation question.[32] The CT DPUC further notes that the Commission did not, in *Mississippi Industries*, seek to dictate where or when or how many generating facilities would be built, and that unlike the situation

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[29] CT DPUC request for rehearing at 16-17, *citing Northwest Central* at 514.

[30] CT DPUC request for rehearing at 17, *citing Northwest Central* at 515-16.

[31] 808 F.2d 1525, 1542 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1978).

[32] CT DPUC request for rehearing at 20.

in *Mississippi Industries,* which involved a system in which generating capacity was built on a highly integrated basis, in New England there is no similar integrated system and all decisions about planning and building generation are made by individual market participants. And finally, the CT DPUC notes that *Groton* and *Mississippi Industries* were decided prior to, and have now been superceded by, the Supreme Court's *Northwest Central* decision.

Commission Ruling

33. The Commission has considered the question of its jurisdiction over capacity requirements set by regional transmission organizations many times. As we most recently stated in *ISO New England, Inc.*,[33] section 201(b)(1) of the FPA confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and over sales of electric energy at wholesale in interstate commerce, and "all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable."[34] In that order, which accepted ISO-NE's ICR determination for the 2007/2008 Power Year, we reaffirmed that the determination of a system's capacity requirement is a "rule or regulation affecting or pertaining to" the charges for the wholesale sale of

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[33] 119 FERC ¶ 61,161 (2007) (2007/2008 Power Year ICR Order).

[34] 16 U.S.C. § 824(b)(1) (2000).

electric energy in interstate commerce.[35] In response to the CT DPUC's argument that Congress did not intend any practice "affecting" rates and charges to trump the FPA's reservation of jurisdiction over resource adequacy to the states, we note here again that, as discussed in the February 28 Order, we are not considering just any practice affecting rates and charges. Rather, we are looking at what the February 28 Order characterized as a "principal" determinant of rates and charges.[36]

34. In the 2007/2008 Power Year Order, we further reaffirmed our reliance on the *Mississippi Industries* and *Groton* precedents. First, we noted that, in *Mississippi Industries*, the court had recognized the connection between the allocation of capacity and wholesale rates:

> In that proceeding, the Commission had altered the allocation of capacity and costs of a nuclear generation plant among operating

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[35] 2007/2008 Power Year ICR Order at P 23 ("the ICR is one of the principal determinants of the price of capacity and, therefore, falls within the Commission's jurisdiction to review 'any rate, charge or classification' charged by a public utility for electric transmission or sales subject to Commission jurisdiction, and 'any rule, regulation, practice, or contract affecting such rate, charge or classification.' ").

[36] *See* February 28 Order at P 15 ("the FCM settlement 'establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales, bringing it squarely within the Commission's jurisdiction under the FPA,' " *citing* FCM Order at P 201).

> companies of an integrated utility system. Petitioners asserted that, in allocating the cost and capacity of the nuclear plant, the Commission had asserted jurisdiction over generating facilities in direct violation of the FPA section 201(b) prohibition against Commission regulation of generating facilities. . . . The court rejected the claim that this action was beyond the Commission's FPA jurisdiction. Instead, it found that the Commission has authority over the allocation of capacity among market participants because this allocation affects wholesale rates.[37]

35. We pointed to the court's statements that "[c]apacity costs are a large component of wholesale rates" and therefore the share of the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy,[38] and that while the allocation of capacity did not set sales prices, it directly affects costs and "consequently, wholesale rates."[39] We also cited the court's conclusion that "FERC's jurisdiction under such circumstances is unquestionable"[40] and that "[p]etitioners ignore the critical point here that, while these provisions [allocating capacity] do not fix wholesale rates, their

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[37] 2007/2008 Power Year ICR Order at P 20.

[38] *Id.*, *citing Mississippi Industries* at 1541.

[39] 2007/2008 Power Year ICR Order at P 20.

[40] *Id.*, *citing Nantahala Power & Light Co.*, 426 U.S. 953 (1986).

terms do directly and significantly *affect* the wholesale rates at which the operating companies exchange energy, due to the highly integrated nature of the . . . system."[41]

36. In the 2007/2008 Power Year ICR Order we further noted that, in *Groton*, the court upheld the Commission's authority to review a NEPOOL rule requiring that each NEPOOL participant who was deficient in its capacity requirement pay a deficiency charge. We stated that:

> The court found that these charges are within Commission jurisdiction because they are under "the Commission's inclusive jurisdictional mandate – which reaches discriminatory practices 'with respect to' jurisdictional transmissions, or 'affecting' such transmissions or services. . . ."[42] The court further stated "[i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge. This is well within the Commission's authority as delineated in other court opinions."[43] [44]

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[41] Power Year ICR Order at P 20, *citing Mississippi Industries* at 1542.

[42] *Groton* at 1302.

[43] *Id.*, *citing*, *e.g.*, *FPC v. Conway Corp.*, 426 U.S. 271 (1976).

[44] 2007/2008 Power Year ICR Order at P 21.

37. We then found that "maintaining adequate resources has a significant and direct effect on jurisdictional rates and services and therefore falls within the Commission's jurisdiction."[45] We stated that this finding was fully consistent with *Mississippi Industries* and *Groton*:

> In *Mississippi Industries*, the Commission exercised jurisdiction over the allocation of the capacity of a nuclear generating plant, despite the fact that the FPA does not give the Commission jurisdiction over generating facilities (and indeed reserves that jurisdiction to the states). The [Supreme C]ourt affirmed Commission jurisdiction because of the nexus between the allocation of capacity and the justness and reasonableness of jurisdictional rates under the Entergy System Agreement. The court in *Groton* undertook a similar analysis in upholding Commission jurisdiction in that case. In *Groton*, the Commission had asserted jurisdiction over a charge related to resource adequacy requirements in New England. The court upheld the Commission's order, finding that that charge affected jurisdictional rates and that jurisdiction remained "irrespective of the objective underlying that charge."[46]

38. Thus, the Commission has previously ruled, and reaffirms here, that ISO-NE's method of determining

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[45] *Id.* at P 24.

[46] *Id.*, *citing Groton* at 1302.

its ICR (the amount of capacity that its member LSEs must provide) has a sufficiently immediate and direct effect on the rates, terms and conditions of the sale of electric energy in interstate commerce that it falls within the Commission's jurisdiction.

39. The CT DPUC's citation to *Northwest Central* does not assist it. *Northwest Central* speaks to the question of whether a federal agency's regulation of a particular area pre-empts state regulation in that area. This is not the case here: as discussed above, the Commission is not seeking to pre-empt (and has not pre-empted) the state's decision-making as to when or where or how many new generating facilities should be built in that state, and ISO-NE's determination of the amount of capacity that each LSE must procure does not render the state unable to go through that decision-making process. Thus, there is no pre-emption of state authority of the kind in issue in *Northwest Central*.[47]

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[47] Additionally, assuming *arguendo* that the Commission was in fact pre-empting state decision-making authority, so that *Northwest Central* did apply, the Commission's actions here would pass the *Northwest Central* test. The CT DPUC asserts that, in *Northwest Central*, the Supreme Court found that a practice that merely "affects" rates or charges does not negate the FPA's reservation of jurisdiction over resource adequacy to the states, unless state determination of resource adequacy would prevent attainment of Commission goals, and that the Commission has not made a showing here that any Commission goal would not be attained. Given the existence of an integrated regional-wide system in New England, and given the absence of a region-wide resource adequacy determination process in New

(Continued on following page)

Differences Between New England and California

CT DPUC Argument

40. The CT DPUC states that, in relying on the CAISO Order to support its exercise of jurisdiction over the ISO-NE method of determining ICR, the Commission ignored differences between the California and New England energy markets. According to the CT DPUC, the Commission pointed to the possibility that one participant's reliability decisions could negatively impact other participants as demonstrating the need for FERC authority over CAISO's resource adequacy determinations.[48] The CT DPUC states that such "free rider" problems (in which one local area could set a lower reserve requirement than necessary, and the utilities in that

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England as discussed below at P 39, the Commission has made such a showing.

[48] CT DPUC request for rehearing at 22-23, *citing* February 28 Order at P 17, *citing* CAISO Order at P 1113 ("where an interconnected transmission system is operated on a regional basis as part of an organized market for electricity . . . all users of the system are interdependent, particularly with respect to reliability, i.e., one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory").

area would then "lean on" capacity provided in other local areas) will not arise in New England, because the New England states have a long tradition of pooling of capacity resources for the benefit of all parties, and because under the FCM, each local area will have a capacity requirement based specifically on how much capacity is present in and can be imported into that area.

41. The CT DPUC further argues that the Commission's concern with bid caps in California does not justify its exercise of jurisdiction over the New England capacity market. In the February 28 Order, the Commission noted that, in approving bid caps to protect against market abuse in energy markets in California, it had found that, unless there were some mechanism (other than increases in the price of energy) to encourage the construction of new generation, such as a robust capacity market, "it would be difficult for us to approve such bid caps [, which] . . . would simply inhibit new supply, and thereby harm customers."[49] The CT DPUC asserts that in New England, however, unlike in California, the FCM's Peak Energy Rent mechanism "is intended to mitigate incentives to create price spikes in the energy market,"[50] so that the bid cap in New England is now, in essence, irrelevant, and the Commission's

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[49] CAISO Order at P 1114, *cited in* February 28 Order at P 18.

[50] CT DPUC request for rehearing at 24, *citing* FCM Order at P 29.

fear that bid caps will inhibit the construction of new supply is groundless. The CT DPUC also asserts that the FCM provides sufficient incentives to attract new infrastructure where needed.

Commission Ruling

42. Neither of the CT DPUC's arguments here are valid. In the 2007/2008 Power Year ICR Order, we stated that we had addressed precisely this jurisdictional question in the CAISO Order, and noted that "the Commission recognized the importance of resource adequacy requirements in meeting our statutory mandate under the FPA to ensure that the rates, terms and conditions of jurisdictional and transmission sales of electric energy in CAISO markets are just, reasonable and not unduly discriminatory or preferential."[51] It is inaccurate to assert, as the CT DPUC does, that the Commission was concerned solely with possible free rider problems. Whether or not the New England LSEs have a practice of pooling capacity resources for the benefit of all, as the CT DPUC states, is irrelevant to the possibility that concerned the Commission – namely, that within a large integrated system such as the New England control area, reliability actions taken by one local area could have an adverse effect on neighboring local areas. This problem can occur even absent any intent to lean on a neighbor's

[51] 2007/2008 Power Year ICR Order at P 27.

capacity: for instance, a project built to address one state's reliability needs might, because of its location and impact on the interstate transmission system, inadvertently cause reliability problems for a neighboring state. Therefore, as the Commission stated, "in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory or preferential."[52]

43. Similarly, the CT DPUC's argument that the Commission's reliance on the CAISO Order and CAISO Rehearing Order to support its exercise of jurisdiction over the determination of ICR has been vitiated by the FCM's Peak Energy Rent mechanism is incorrect.[53] The CT DPUC argues that, in those two orders, the Commission supported its assertion of

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[52] *Cal. Indep. Sys. Operator Corp.*, 115 FERC ¶ 61,172 at P 36-37 (2006), *order on rehearing*, 118 FERC ¶ 61,045 (2007); *see also, Gainesville Utils. Dep't v. Fla. Power Corp.*, 402 U.S. 515, 529 (1979) (the Commission has a "responsibility to the public to assure reliable efficient electric service").

[53] The Peak Energy Rent mechanism seeks to stabilize prices by deducting from capacity prices amounts that might hypothetically be earned in the energy market during price spikes. *See* FCM Order at P 29 ("the peak energy rent deduction is intended to help mitigate incentives to create price spikes in the energy market [because it] will remove any profits gained from the rise in prices because the extra revenues earned in the energy market are deducted from capacity payments").

jurisdiction over resource adequacy by pointing to the fact that the Commission had found that, due to the bid caps in the CAISO energy markets, the construction of new supply might be inhibited unless the market design contained some other mechanism to ensure sufficient construction of supply. Here, in contrast, the CT DPUC states, since the Peak Energy Rent mechanism has ensured that New England's bid caps will never be activated, there is no need for the Commission to exercise jurisdiction.

44. This argument mistakes the nature of the Commission's concerns in the CAISO Order and CAISO Rehearing Order. We stated there:

> [R]esource adequacy plays an important role in addressing whether Commission-jurisdictional wholesale prices reflect the exercise of market power or the scarcity of supply. In particular, we are approving bid caps for the markets operated pursuant to the [Market Redesign and Technology Upgrade] Tariff. These bid caps are premised on the notion that bids above these levels may not reflect true scarcity pricing, but rather the exercise of market power or abuse that results in rates that are not just and reasonable. This premise is only valid, however, if there is some mechanism – other than energy price increases -- to encourage the construction of new generation where and when needed. Consequently, in the absence of a workable resource adequacy program, it would be difficult for us to approve such bid caps. Without a workable

> program, the bid caps would simply inhibit new supply, and thereby harm customers, rather than protecting customers from the exercise of market power or abuse.[54]

45. The Commission focused on the fact that, in approving California's tariff provisions (which are clearly within the Commission's jurisdiction), we had put into place a market design that contained an element that could, potentially, inhibit the construction of necessary new generation and ultimately harm electricity customers. Thus, it was critical that the Commission be able to ensure that the market design also included a countervailing mechanism to ensure the construction of new generating capacity – in this case, a capacity market that sent appropriate price signals to encourage the development of new capacity. Absent the power to ensure that capacity prices correctly reflect the value of capacity, so as to make sure that necessary capacity is provided to the system, the Commission could not have approved a market design that included bid caps. This is equally true in New England, where the market design similarly contains bid caps; whether the Peak Energy Rent mechanism will modulate energy price spikes to a sufficient degree to render those bid caps irrelevant is an as-yet-untested proposition.

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[54] CAISO Order at P 1114.

Deference to New England States

CT DPUC Argument

46. The CT DPUC states that, despite paying lip service to the concept of respecting state decision-making with respect to resource adequacy, the Commission has failed to do so and now asserts that it retains absolute jurisdiction to override any state's resource adequacy determination. As evidence of this, the CT DPUC states that the Commission has not acted on the petition for declaratory order filed by six New England governors in June 2004 asking the Commission to state that the governors' proposed New England States Committee on Electricity (NESCOE) would have authority to make resource adequacy determinations.[55] The CT DPUC states that it has proposed a specific mechanism under which the states would determine ICR, based on information provided by ISO-NE. The CT DPUC states that, on rehearing, the Commission should either reject ISO-NE's proposed ICR rules as beyond the Commission's jurisdiction to accept, or impose and direct ISO-NE to file rules that reflect the CT DPUC's proposal.

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[55] CT DPUC request for rehearing at 27, *citing* Joint Petition for Declaratory Order to Form a New England Regional State Committee, *Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont*, Docket No. EL04-112-000 (June 25, 2004).

Commission Ruling

47. In the 2007/2008 Power Year ICR Order, the Commission reiterated that

> as a general matter, a state or region may determine in the first instance the appropriate level of planning reserves by balancing reliability and cost considerations. Citing the CAISO Order [in the CAISO Rehearing Order], we noted that "it is our responsibility to ensure that a workable resource adequacy requirement exists in a market such as that operated by the CAISO. This does not mean that we must determine all the elements of such a program in the first instance. Rather, we can, in appropriate circumstances, defer to state and Local Regulatory Authorities to set those requirements."[56]

48 The Commission has not changed its view. However, the CT DPUC does not point to a completed and ready-to-implement program for determining capacity requirements by the states. Rather, the CT DPUC points to a proposal filed in June 2004 by the New England governors. On July 7, 2005, the Commission issued an order deferring action, and encouraging further discussion among the stakeholders.[57] In its most recent status report, filed on

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[56] 2007/2008 Power Year ICR Order at P 29, *citing* CAISO Rehearing Order, 119 FERC ¶ 61,076 at P 558, *citing* CAISO Order, 116 FERC ¶ 61,274 at P 1117.

[57] *Governors of: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont*, 112 FERC ¶ 61,049 (2005).

July 13, 2007, ISO-NE stated that it had prepared a draft Schedule 5 to its tariff, which was intended to be the vehicle for funding NESCOE, and which was approved at a July 6, 2007 meeting of the NEPOOL Participants Committee. ISO-NE further stated that it, NEPOOL and the state parties had been actively working on a filing letter pursuant to which the Commission would be asked to approve Schedule 5, and it hoped to make this filing before the next status report would be due, ninety days from July 6, 2007.[58] Subsequently, on August 31, 2007, in Docket No. ER07-1324-000, ISO-NE and others submitted proposed Schedule 5 to the tariff, which would provide for funding NESCOE costs through the tariff; that filing is presently pending, with interventions and protests presently due on or before September 21, 2007. Thus, NESCOE is still in the process of formation, rather than being an organization that is fully capable, at this time, of making resource adequacy determinations. As a result, as the Commission stated in the February 28 Order, "[t]here is no agreement among the New England states to establish the ICR and therefore nothing to which we could defer."[59]

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[58] *Governors of: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont*, Docket No. EL04-112-000, Eighth Status Report, filed July 6, 2007.

[59] February 28 Order at P 21.

Cross Sound Cable Issues

49. In the February 28 Order, the Commission addressed the issue of the treatment of tie benefits provided by the Cross Sound Cable.

50. "Tie benefits" are an estimate as to the amount of emergency assistance that is likely to be available to a control area as a result of its interconnections with neighboring control areas.[60] Thus, once the level of tie benefits is determined, the ICR number (i.e., MW of capacity that the ISO must procure) is reduced by that amount of tie benefits.

51. The Commission addressed the treatment of the estimate of tie benefits provided to New England by the Hydro-Quebec Phase II Interconnection (HQ Interconnection), a transmission intertie between New England and Quebec, and the treatment of the

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[60] In the February 28 Order at P 23, we stated:

> According to ISO-NE, tie benefits are a result of resource and load diversity between two control areas; for example, when New York has excess resources at a time when New England's resources are tight, New York resources could support New England's load to the extent that transmission constraints allow. . . . Thus, for example, if ISO-NE determines that it needs 30,000 MW of installed capacity in order to meet its reliability objective and it determines that tie benefits total 1,000 MW, the ICR would be 29,000 MW. In this case, LSEs in the aggregate would need to acquire 29,000 MW of capacity through the FCM auction. The remaining 1,000 MW of capacity needed for reliability (the tie benefit) would be assumed to be available in an emergency from the neighboring control area.

estimate of tie benefits provided by the Cross Sound Cable, a transmission intertie between New England and New York. ISO-NE's market rules provide for the calculation of the tie benefits provided by the HQ Interconnection between New England and Hydro-Quebec by a deterministic methodology that uses forecasted load and capacity for the Hydro-Quebec control area and the HQ Interconnection transfer limit as determined by ISO-NE, in order to arrive at a specific amount of capacity that will be available for tie benefits on the HQ Interconnection interface. The rules also provide, however, for the use of a probabilistic methodology that quantifies firm capacity equivalents to express the probable amount of capacity that will be available on the interface for other transmission interties, including the Cross Sound Cable. As a result of this difference,

> parties utilizing the HQ Interconnection will have a higher degree of certainty as to the amount of capacity that will be available to them than parties utilizing the Cross Sound Cable [, and] transmission capacity across the HQ Interconnection is likely to receive a higher price than transmission capacity across the Cross Sound Cable and other transfer facilities as to which there is a lesser degree of certainty.[61]

52. LIPA, the owner of all firm transmission capacity on the Cross Sound Cable, asserted that this

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[61] *Id.* at P 33 n.30.

difference was discriminatory, on the basis that the two interties were equivalent in that they are both privately-owned, are both high voltage direct current (HVDC) facilities, and function in the same manner (i.e., both the HQ Interconnection and the Cross Sound Cable are direct current (DC) facilities, such that the direction of flows can be controlled). LIPA argued that a deterministic methodology (that would arrive at a definitive figure for the tie benefits) was more appropriate to measure the tie benefits for both DC facilities, where flows can be controlled, than a probabilistic methodology (that develops a probable estimate of tie benefits) appropriate for alternating current (AC) interface facilities, where the flows cannot be controlled. LIPA further argued that the owners of the HQ Interconnection receive capacity credits, in recognition of the contribution to tie benefits that the HQ Interconnection makes to the New England system, and LIPA, as the holder of all firm transmission rights on the Cross Sound Cable, believes that it is entitled to similar capacity credits. LIPA states that while it has raised this issue in the New England stakeholder process, it has received no relief.[62]

53. The Commission disagreed with LIPA's view. We stated that, while both the HQ Interconnection and the Cross Sound Cable are HVDC, controllable interconnections, "there are other important differences

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[62] LIPA protest at 17-18.

between the two facilities."[63] We pointed to the fact that ISO-NE is required to submit specific HQ Interconnection values, as required in a prior Commission order.[64] The Commission stated that, in that order, it had relied on the fact that:

> the deterministic method was appropriate there because all of the capacity transferred from the [Hydro-Quebec] control area to New England [is] sent through the HQ Interconnection. Thus, the determination of tie benefits available through the HQ Interconnection was based on the availability of all of the generating capacity from Quebec that can be accessed through the HQ Interconnection, rather than on an estimate of the likelihood that New England would require emergency assistance.[65]

54. We found that equivalent treatment for the Cross Sound Cable, however, would not take into account the fact that, when capacity is transferred from New York to New England, that transfer occurs

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[63] February 28 Order at P 35.

[64] *Id.* at P 36, *citing New England Power Pool*, 111 FERC ¶ 61,132 (2005) (HQ Order). In the HQ Order, the Commission endorsed a deterministic method for calculating HQ Interconnection capacity ("ISO-NE used a deterministic approach to calculate the Monthly Capacity Potentially Available for Sales (MCPAS) and the corresponding monthly Capacity Credit values [which] requires a set of load and resource assumptions that describes the expected system conditions.") HQ Order at P 8; *see also Id.* at P 19.

[65] February 28 Order at P 36.

not only across the Cross Sound Cable, but also two other transmission interties between the two control areas. And, because those two other interties are uncontrollable AC facilities,

> it is not possible to know in advance how much capacity will flow through those facilities. Therefore, it is similarly not possible to know in advance how much transmission capacity on the Cross Sound Cable will be necessary at any given time for emergency assistance.[66]

55. Therefore, the Commission ruled that it would not direct ISO-NE to quantify the tie benefits on the Cross Sound Cable in a similar way to its treatment of the HQ Interconnection.

LIPA's Request for Rehearing

56. LIPA challenges this determination. It states that the Commission engaged in arbitrary, capricious and discriminatory decision-making when it refused to treat the Cross Sound Cable comparably with the HQ Interconnection. LIPA asserts that the Commission failed to recognize the reliability benefits provided by the Cross Sound Cable, while at the same time grandfathering an earlier treatment of the HQ Interconnection.

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[66] *Id.* at P 37.

57. LIPA first states that the Commission accepted ISO-NE's assertion that the tie benefits provided by the Cross Sound Cable must be weighed together with the energy flowing over the AC facilities interconnecting New York and New England, and that this assertion was not based on any study. LIPA states that this action "exclude[d] consideration of the unique characteristics of the HVDC [Cross Sound Cable] . . . from appropriate consideration in that process."[67] LIPA argues that:

> ISO-NE's premise that the preferential and grandfathered treatment [of the] HQ Interconnection is justified because it is the only interconnection between Quebec and New England while there are multiple interfaces between New England and New York, has no basis in electric reality. That premise is factually incorrect. The transmission system of Hydro-Quebec for the Canadian Province of Quebec is interconnected with all of New York, New England, Ontario New Brunswick and Newfoundland and Labrador.[68]

58. LIPA then asserts that the Commission erred by assuming that any capacity from Long Island that may be provided over the Cross Sound Cable is "more speculative" than the capacity available over the HQ Interconnection. LIPA states that this conclusion is not consistent with the 2007 Reliability Needs

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[67] LIPA request for rehearing at 5.

[68] *Id.*, footnote omitted.

Assessment of capacity available in the New York control area, which shows that Long Island will have "substantial excess capacity" above its planning requirement throughout the ten-year period studied in the Reliability Needs Assessment.[69] LIPA states that, as controllable HVDC interties, both the Cross Sound Cable and the HQ Interconnection are able to direct and regulate the flows across these facilities, and should therefore be treated equally, and the tie benefits provided by each facility should be assessed in a comparable manner. LIPA states that the Commission's assent to ISO-NE's proposal will result in treating the Cross Sound Cable as if it could provide only the level of reliability benefits provided by an AC intertie, a result that LIPA considers unjust and unreasonable.

59. LIPA also challenges the methodology by which ISO-NE measured capacity and reliability, and incorporation of tie benefits. LIPA asserts that ISO-NE's methodology is inconsistent with the methodology used by New York, and does not, therefore, take an appropriate regional approach. LIPA asserts that ISO-NE starts with a model of ISO-NE in an unconstrained state, then measures capacity in other areas on a static basis to measure tie benefits. By contrast, LIPA states that the New York approach examines that New York control area together with

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[69] *Id.* at 7, *citing* affidavit of Curt Dahl, Attachment A to LIPA request for rehearing. Mr. Dahl's affidavit in turn attaches the 2007 Reliability Needs Assessment.

the flows over the interties to the PJM and New England control areas. LIPA claims that ISO-NE's methodology effectively discriminates against capacity from other areas, and perpetuates a seam between the New York and New England control areas. LIPA also asserts that it is inconsistent for ISO-NE to justify its discriminatory treatment of the Cross Sound Cable based on the existence of other interties between New York and New England, when at the same time ISO-NE's methodology for developing the ICR ignores those interties. LIPA considers this a fundamental flaw in ISO-NE's ICR methodology that justifies rejection by the Commission.

60. Finally, LIPA asserts that the Commission should not have relied on its own past treatment of the HQ Interconnection in the HQ Order, when that 2005 order did not establish the ICR requirement, but rather simply addressed capacity credits to be granted to the HQ Interconnection owners.

Commission Ruling on Rehearing

61. The Commission denies LIPA's request for rehearing.

62. In the February 28 Order, the Commission found that, while both the Cross Sound Cable and the HQ Interconnection (both DC facilities) brought energy from external control areas into New England, it was more difficult to quantify how much energy will flow over the Cross Sound Cable than over the HQ Interconnection. This is because, while all of the

energy that moves from Quebec to New England flows over the HQ Interconnection, this is not the case with the energy moving from New York to New England. As noted in the February 28 Order, there are other, AC interties between New England and New York; when energy flows from New York to New England some of it will flow across the Cross Sound Cable, and some will flow across the AC interties and it is not possible to estimate the amount of transfer capacity on the Cross Sound Cable that would be used during an emergency to bring energy from New York to New England.[70] Thus, the Commission found that while it was able to develop an estimate of the tie benefits that the HQ Interconnection provided to New England (especially since it was able to rely on prior Commission rulings as to the appropriate methodology for evaluating the capacity provided by the HQ Interconnection[71]), it was not able to identify the tie benefits that are specifically attributable to the Cross Sound Cable.

63. LIPA challenges this view, stating that the Commission is failing to take account of the fact that "[t]he transmission system of Hydro-Quebec for the

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[70] *See* February 28 Order at P 37 & n.33 (listing additional AC interties, and noting that "it is not possible to know in advance how much capacity will flow through those facilities").

[71] February 28 Order at P 36, *citing New England Power Pool*, 111 FERC ¶ 61,132 at P 19 (2005) (Commission accepts NEPOOL's and ISO-NE's values for the capacity credits associated with the HQ Interconnection and approves the methodology used to determine those credits).

Canadian Province of Quebec is interconnected with all of New York, New England, Ontario New Brunswick and Newfoundland and Labrador."[72] However, LIPA misstates the basis of the reasoning behind the Commission's evaluation of the amount of tie benefits that the HQ Interconnection brings to New England. Whether some generation in Quebec could reach New England indirectly by way of other control areas is not relevant to the calculation of the tie benefits attributable to the HQ Interconnection. The tie benefit associated with a neighboring control area is based on the smaller of (i) the control area's surplus generating capacity estimated to be available to New England in an emergency, or (ii) the amount of transfer capability to import the associated energy. The transfer capability of the HQ Interconnection is smaller than the surplus generation capacity in Quebec. HQ has sufficient surplus generation capacity to fill not only the HQ Interconnection to New England but also the remaining DC interconnections between the HQ system and other areas such as New York and New Brunswick.[73] Phrased another way, the HQ Interconnection, by itself, makes

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[72] LIPA request for rehearing at 5.

[73] The HQ Interconnection has roughly 1,800 MW of transmission capability, while Quebec has many times that much surplus energy during the non-winter months. Indeed, the amount of non-winter surplus generation in Quebec is substantially greater than the combined transmission transfer capabilities of all the DC lines leading out of Quebec to all of its neighboring control areas.

additional surplus generation available to New England in an emergency, in that this surplus generation would not be available if the HQ Interconnection did not exist. As a result, the HQ Interconnection transmission capability provided to the system by the Interconnection Rights Holders (IRHs) measures the amount of energy that New England could directly import from Quebec in an emergency situation. The amount of this transmission capability should reasonably be counted as a tie benefit and used to meet the capacity obligations of the IRHs. If the HQ Interconnection were to be removed, the amount of energy that New England could procure in an emergency from Quebec would be reduced by the full amount of HQ Interconnection's capacity.[74]

64. By contrast, LIPA has not demonstrated that the Cross Sound Cable, by itself, makes any additional surplus generation available to New England; if the Cross Sound Cable did not exist, New England would have the same amount of surplus New York generation available to it in an emergency. In New York, the amount of surplus transmission capability exceeds the amount of surplus generation capacity. Thus, the tie benefit from New York into New

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[74] Even if Quebec were to export surplus generation to New England indirectly by using its other DC ties that lead to other control areas (such as New York), that generation would need to use transmission capacity that connects New York to New England, and New York transmission capability has already been considered in determining New England's tie benefits from New York.

England is limited by the amount of surplus generating capacity available in New York, not the amount of surplus transmission capacity (both over the Cross Sound Cable, and over the other AC interties) over which that generation could flow. If the Cross Sound Cable were to experience an outage, there would still be other AC transmission capability in New York that could be used to import the limited amount of surplus energy available from New York. So, removing the Cross Sound Cable would not reduce the amount of generation capacity in New York that New England could import in an emergency. Further, if surplus energy flowed from New York to New England in an emergency situation over both the Cross Sound Cable and other AC interties, it would not be possible to quantify the extent of tie benefits that the Cross Sound Cable provides to the New England control area, given that some energy will flow on the Cross Sound Cable and other energy on the AC ties between New England and New York.[75]

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[75] Moreover, Quebec is electrically separate from the United States and the rest of the Canada due to its DC ties (and lack of AC ties). The Hydro-Quebec control area is a single, discrete synchronous "interconnection" (i.e., a power grid in which, during normal system operating conditions, all of its electric utilities are tied together and operate at a single synchronized frequency) tied to other interconnections only with DC ties (i.e., all load and generation within a given interconnection operates at a frequency that is independent of actions and events in adjacent interconnections). All of the interties between Hydro-Quebec and other control areas are DC ties like the HQ Interconnection. Thus, all of the energy flowing from Hydro-Quebec to other

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65. The fact that Long Island, specifically, is projected to have large amounts of excess generating capacity by 2010 is not relevant to the calculus of tie benefits provided to New England by the Cross Sound Cable at this time. If the total amount of generation available from all of the New York control area should change, such that it would be appropriate to re-evaluate the tie benefits to New England from New York, ISO-NE's market rules already provide for that contingency: pursuant to Market Rule III.12.9, at least once every three years, ISO-NE must perform a tie benefits study, and will update its tie benefits analysis if it determines that changes in the New England control area or adjacent control areas warrant such changes.

66. LIPA further asserts that the Commission should not have relied on its HQ Order to establish the amount of tie benefits that could flow over the HQ Interconnection. The Commission did not, in the February 28 Order, rely on the HQ Order in that fashion. Rather, our observation was that, because of

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control areas is over ties that are controllable in a way that AC ties are not. By contrast, New York and New England, are not separate interconnections but form part of a single synchronous network that includes free-flowing AC ties that parallel controllable DC ties such as the Cross Sound Cable. Thus, the fact that the transmission system of Hydro-Quebec is interconnected via separate DC ties with New York, New England and New Brunswick does not support LIPA's argument.

that order, we could more easily quantify the amount of capacity flowing over the HQ Interconnection.[76]

67. Finally, LIPA makes specific technical challenges to the methodology by which ISO-NE measured capacity and reliability, and incorporation of tie benefits. It states:

> ISO-NE's approach to measuring capacity and reliability and incorporation of "tie benefits" is inconsistent with New York's . . . methodology and does not take the appropriate regional approach. . . . Although ISO-NE justifies its discriminatory treatment of the Cross Sound Cable based upon the existence of other interties between New York and New England, ISO-NE's methodology for developing the ICR ignores those interties.[77]

Thus, LIPA claims, "[t]he ISO-NE methodology effectively discriminates against capacity from other areas and perpetuates a seam between the New York and New England Control Areas."[78]

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[76] February 28 Order at P 36 ("ISO-NE is required to submit specific HQ Interconnection values, as required in a prior Commission order, [in which] the applicants provided that the deterministic method was appropriate there because all of the capacity transferred from the HQ control area to New England are sent through the HQ Interconnection").

[77] LIPA request for rehearing at 8-9.

[78] *Id.* at 8.

68. The Commission's responsibility in this case is not to measure the ISO-NE methodology against the NYISO methodology to determine which is superior, but to determine whether the ISO-NE methodology is just and reasonable. The Northeast Power Coordinating Council (NPCC) is the regional entity responsible for coordinating planning studies.[79] All members of the NPCC are required to meet the basic criteria for normal and emergency operations, as well as resource adequacy design criteria specifying sufficient resources to meet a loss of load expectation of no more than 0.1 days per year, as outlined in NPCC Documents A-02, A-03 and B-08, respectively.[80] The NPCC stated in its June 2004 tie benefits study that its CP-8 Working Group had concluded that "the interconnection assistance values reported by NPCC Areas in their recent resource adequacy assessments appear to be reasonable and do not overstate interconnection benefits."[81] In addition, the ISO-NE

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[79] Bylaws of Northeast Power Coordinating Council, Inc., *see* http://www.npcc.org/publicFiles/NPCC_INC_Bylaws.pdf.

[80] NPCC Document A-02, "Basic Criteria for Design and Operation Of Interconnected Power Systems," *see* https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/A-02.pdf; NPCC Document A-03, "Emergency Operation Criteria," *see* https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/A-03.pdf; and NPCC Document B-08, "Guidelines for Area Review of Resource Adequacy," *see* https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/B-08.pdf.

[81] "Review of Interconnection Assistance Reliability Benefits," *see* https://www.npcc.org/publicFiles/documents/interconnection

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method does not ignore the other ties between New York and New England as LIPA states; those ties are, in fact, included in the analysis.[82]

69. The stakeholders of New York and New England agreed to ICR methodologies in their respective regions and any disputes over such methodologies, or attempts to change them, should be pursued through the relevant stakeholder processes in the first instance. LIPA states that it has so far been unsuccessful in persuading other New England stakeholders to treat the tie benefits provided by the Cross Sound Cable as equivalent to the tie benefits provided by the HQ Interconnection.[83] The fact that others may not see things LIPA's way does not mean that LIPA is right and others are wrong. In any event, the comparatively brief explanation that LIPA provides here of its criticism of the methodology used

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AssistanceReliabilityBenefits/archives/RCC_Approved_CP-8_Tie_Benefit_Report.pdf.

[82] Key modeling assumptions that go into the tie benefit analysis are the transfer limits between New York, New England, Ontario and the Canadian Maritimes. Review of Interconnection Assistance Reliability Benefits, *see* https://www.npcc.org/publicFiles/documents/interconnectionAssistanceReliabilityBenefits/archives/RCC_Approved_CP-8_Tie_Benefit_Report.pdf.

[83] LIPA protest at 15 ("As a participant in the ICR Working Group . . . LIPA made a presentation and proposal to the ICR Working Group to treat the Cross Sound Cable consistent with the HQ Phase II line. . . . The equivalent treatment of the [Cross Sound Cable] was *rejected by the NEPOOL Review Committee* and the NEPOOL Participants Committee at the September 8, 2006 meeting").

by ISO-NE and its own very different approach, however, is not sufficient for the Commission to find that we should adopt LIPA's very different approach, and we will not, therefore, grant LIPA the relief it requests.

The Commission orders:

The Commission hereby denies both requests for rehearing, as discussed above.

By the Commission.

(SEAL)

Kimberly D. Bose,
Secretary.

APPENDIX E

119 FERC ¶ 61,161
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before
Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

ISO New England Inc. ER07-655-000

ORDER ON INSTALLED CAPACITY REQUIREMENTS

(Issued May 18, 2007)

1. On March 23, 2007, ISO New England, Inc. (ISO-NE) submitted for filing its Installed Capacity Requirements (ICRs) for the 2007/2008 Power Year[1] pursuant to the Commission's April 30, 2003 order in *NSTAR Electric and Gas Corporation v. New England Power Pool*[2] and section 205 of the Federal Power Act (FPA).[3] In this order, we accept ISO-NE's ICRs, effective May 22, 2007.

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[1] ISO-NE's 2007/2008 Power Year runs from June 1, 2007 through May 31, 2008.

[2] *NSTAR Elec. and Gas Corp. v. New England Power Pool*, 103 FERC ¶ 61,093 (2003) (April 30, 2003 Order).

[3] 16 U.S.C. § 824d (2000).

I. Background

2. For over 20 years, ISO-NE has imposed ICRs on its members in order to maintain adequate system reliability.[4] On April 20, 1998, ISO-NE began operating an installed capacity (ICAP) market through which it required load serving entities (LSEs) to procure a specified amount of ICAP each month based on the particular LSEs' projected peak demand and a required reserve margin. However, because of transmission constraints, not all energy produced from qualified ICAP resources could be delivered to all loads in the region. Due to the lack of needed infrastructure upgrades in designated congestion areas and the reliability must run agreements being filed by older generating facilities, the Commission set for hearing the ISO-NE's compliance filing for a locational installed capacity (LICAP) market in New England.[5]

3. On June 16, 2006, the Commission issued an order accepting a settlement in the LICAP proceeding.[6] That settlement includes transition payments for installed capacity through May 31, 2010, and initiates a forward capacity market (FCM)

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[4] Prior to the existence of the ISO-NE the requirements were imposed on the members of the New England Power Pool (NEPOOL), and the ICR was then called NEPOOL's Objective Capability (OC).

[5] *Devon Power LLC*, 107 FERC ¶ 61,240 (2004); *see also Devon Power LLC*, 103 FERC ¶ 61,082 (2003).

[6] *See Devon Power LLC* 115 FERC ¶ 61,340 (2006).

mechanism with payments on new resources beginning June 2010 as an alternative to the LICAP market. The FCM settlement also contains provisions for including demand resources, i.e., energy efficiency, load management and distributed generation,[7] and external ICAP such as purchases from the New York Power Authority.

II. The Filing

4. ISO-NE explains that the ICRs are the amount of installed generating capability that is necessary to satisfy the ISO-NE Control Area's total forecasted load requirements and to maintain sufficient reserve capacity in order to meet a reliability standard of disconnecting noninterruptible customers (a loss of load expectation or LOLE) no more than once in ten years (an LOLE of 0.1 day per year).[8]

5. ISO-NE also explains that the methodology undertaken to develop the Power Year 2007/2008 ICR values was developed with stakeholder input and is the same process that was used by NEPOOL for more than 20 years prior to when regional transmission organization (RTO) arrangements began in New England. ISO-NE notes that the 2007/2008 ICR

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[7] *See ISO New England, Inc.*, 119 FERC ¶ 61,045 (2007).

[8] *See* section III.1.3 of ISO-NE's Transmission, Markets and Services Tariff (Tariff). ISO-NE explains that the April 30, 2003 Order required the annual filing of "Objective Capability" (OC) values.

values will not be used for establishing the amount of ICAP to be purchased, as was the case in prior years. ISO-NE will use the 2007/2008 Power Year ICR values to calculate the Annual and Monthly Installed Capacity Reserve Margins for use in determining the Unforced Capacity rating of demand resources, other demand resources and New York Power Authority contracts. ISO-NE explains that the Westinghouse/ APP Capacity Model Program (WCMB)[9] load and resource assumptions were reviewed by the NEPOOL Power Supply Planning Committee, a technical committee that is a subcommittee of the Reliability Committee. ISO-NE further explains that all assumptions, inputs and projections for calculating the 2007/2008 Power Year ICR were agreed upon between ISO-NE and the NEPOOL Power Supply Planning Committee. ISO-NE explains that the ISO-NE Tariff and Participants Agreement are the controlling documents.[10]

6. ISO-NE explains that the ICR values are based on three essential components: (1) unit availability; (2) load forecast; and (3) tie benefits. ISO-NE explains that the methodologies for determining the tie

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[9] ISO-NE includes a description of the WCMB at Attachment 1 to the filing.

[10] *ISO New England*, 118 FERC ¶ 61,157 (2007) (conditionally accepting certain revisions to the ISO-NE tariff to memorialize the process for developing the ICRs) (ISO-NE Order); *see also* Tariff section III.8.1 – Annual Installed Capacity Requirement, and Participants Agreement section 11.4 – Installed Capacity Requirement.

benefits and projected load are the same as those used in last year's filing and the Equivalent Demand Forced Outage Rate (EFORd) methodology for measuring unit availability for the 2005/2006 and 2006/2007 Power Years has been used.[11]

1. Unit Availability

7. ISO-NE explains that the proposed 2007/2008 ICRs reflect unit availability as measured by the EFORd, based upon historical performance over the prior five-year period. Unit availability modeling reflects projected scheduled maintenance and forced outages. Individual generating unit maintenance assumptions are based on each unit's historical five-year average scheduled maintenance. Individual generating unit forced outage assumptions are based on the unit's historical data and North American Electric Reliability Corporation (NERC) average data for the same class of unit.

2. Load Forecast

8. ISO-NE explains it used an historical methodology to develop the load forecast for the 2007/2008

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[11] The EFORd measures the portion of time that a generating unit is in demand, but is unavailable due to forced outages. A generator's ICAP is reduced by its EFORd and by other adjustments in order to determine its UCAP rating, which limits the amount of capacity that it can sell in bilateral contracts or in ISO-NE's capacity market auctions.

Power Year. ISO-NE further explains that the forecasted increase in load followed the trend that has been experienced in recent years. ISO-NE notes that the reference summer peak load forecast for the 2007/2008 Power Year of 27,360 MW is 355 MW higher than the previous reference summer peak load forecast for Power Year 2006/2007 of 27,025 MW.[12] The higher load forecast is the result of normal load growth due to economic and demographic factors, but is moderated by a forecasted increase in the price of electricity.

3. Tie Benefits

9. As in prior years, ISO-NE explains that it was required to make assumptions concerning the tie benefits associated with ISO-NE's interconnections with other neighboring control areas. After discussions with the NEPOOL Power Supply Planning Committee, it was agreed to assume 2,000 MW of tie benefits for the summer months based on the results of the 2003 tie benefits study and the HQICC values previously filed with the Commission. According to ISO-NE, the 2,000 MW consists of 1,200 MW from the Hydro-Quebec Phase II tie, 600 MW from the New York tie and 200 MW from the New Brunswick tie.[13]

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[12] Attachment 3 "ISO New England RSP07 Short-Run Forecast of Energy and Seasonal Peak Loads."

[13] ISO-NE notes that the annual ICR filing does not set any or allocate any installed capacity credit rights for interties.

4. Stakeholder Process

10. ISO-NE notes that the NEPOOL Power Supply Planning Committee forwarded the proposed ICR values to the Reliability Committee for consideration at the February 13, 2007 meeting, where the motion to recommend that the Participants Committee support establishing the 2007/2008 Power Year ICRs was approved with a 96.73 percent vote in favor. At the March 2, 2007 Participants Committee meeting, 89.58 percent voted in support of the 2007/2008 Power Year ICRs.[14]

11. ISO-NE requests an effective date of May 22, 2007, which will enable the use of the ICR values prior to June 1, 2007, the commencement of the 2007/2008 Power Year.

III. Notice, Interventions and Comments and Answer

12. Notice of ISO-NE's filing was published in the *Federal Register*, 72 Fed. Reg. 15874 (2007), with interventions, protests and comments due on April 13, 2007. The Attorney General of the Commonwealth of Massachusetts, NRG Companies,[15] and Northeast

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[14] ISO-NE notes that under the currently effective RTO arrangements in New England, a 60 percent vote in favor is required for Participants Committee action to support a particular set of ICRs values.

[15] The NRG Companies include NRG Power Marketing Inc., Connecticut Jet Power LLC, Devon Power LLC, Middletown

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Utilities (NU) Companies[16] filed motions to intervene. The Massachusetts Department of Public Utilities (DPU) filed a notice of intervention. The NEPOOL Participants Committee (NEPOOL) filed a timely motion to intervene and comments in support of the filing, and the Connecticut Department of Public Utility Control (CT DPUC) filed a notice of intervention, request to reject and protest. The Mirant Parties[17] and Milford Power Company, LLC filed motions to intervene out of time. ISO-NE filed a motion for leave to answer and answer.

13. NEPOOL states that it collaborated with ISO-NE to develop the 2007/2008 Power Year ICR values, which are in accordance with ISO-NE's RTO arrangements. NEPOOL states that the NEPOOL Participants Committee voted overwhelmingly in support of the 2007/2008 Power Year ICR values.[18] NEPOOL urges the Commission to disregard any challenge to the Commission's jurisdiction to oversee establishing

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Power LLC, Montville Power LLC, Norwalk Power LLC, and Somerset Power LLC.

[16] The NU Companies include Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire.

[17] The Mirant Parties include Mirant Energy Trading, LLC, Mirant Canal, LLC, and Mirant Kendall, LLC.

[18] *See* NEPOOL Motion to Intervene at Attachment A (noting that the filing indicates that the Participants Committee supported the 2007/2008 Power Year ICR values by a vote of 89.58 percent in favor, but provides a table indicating an actual vote of 94.7 percent in favor).

ISO-NE's ICRs, as has occurred in two other currently active proceedings, which do not concern the 2007/2008 Power Year ICR values.

14. In its protest, CT DPUC states that it protests ISO-NE's proposed ICR "on the same jurisdictional grounds that the CT DPUC has raised in many previous proceedings."[19] It then states: "For the same reasons that the CT DPUC stated most recently in its request for rehearing in *ISO New England, Inc., et al.*, Docket No. ER07-365-000, [footnote omitted] the Commission should reject this ICR filing as beyond its authority to approve."[20]

IV. Discussion

Procedural Matters

15. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2006), the timely notices of intervention and the unopposed motions to intervene serve to make those parties who filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2006), the Commission will grant the Mirant Parties' and Milford Power's late-filed motions to intervene given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or

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[19] CT DPUC Protest at 2.

[20] *Id.*

delay. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2006), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We are not persuaded to accept ISO-NE's answer and will, therefore, reject it.

16. The Commission need not address arguments CT DPUC has attempted to incorporate into its protest by reference. Incorporation by reference of arguments from prior pleadings in other proceedings is not sufficient to warrant a Commission response to those arguments. For example, in the context of rehearing requests, the Commission has rejected attempts to incorporate by reference arguments from a prior pleading in another proceeding as such incorporation fails to inform the Commission as to which arguments from the referenced pleading are relevant and how they are relevant.[21] Such reasoning is equally applicable here in the context of a protest. We must decide each case on the record in that case, and here what is before us is simply an unexplained and unsupported claim that the Commission lacks jurisdiction to review the proposed ICRs. A party has an obligation to clearly articulate and substantiate the basis for its requested action (in the instant case, rejection of the filing for alleged lack of jurisdiction),

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[21] *See ExxonMobil Chem. Co. v Entergy Services, Inc.*, 112 FERC ¶ 61,255, at P 10 (2005); *see also City of Santa Clara, Calif. v. Enron Power Mktg., Inc.*, 112 FERC ¶ 61,280 at P 8 n.4 (2005).

and not simply make an unsupported claim.[22] In any event, as discussed below, contrary to CT DPUC's claim, we find that the Commission has jurisdiction to act on the instant filing.

Commission Determination

17. We have reviewed the ICRs established by ISO-NE for the 2007/2008 Power Year and find them to be reasonable and consistent with the FCM settlement. Accordingly, we will accept the ICRs, to become effective May 22, 2007, as requested.

18. We now consider the only objection to the Commission's acceptance of the ICR for the 2007/2008 Power Year, the Commission's jurisdiction over the ICRs.[23] We begin our analysis of the Commission's

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[22] *See, e.g., Pub. Serv. Elec. and Gas v. FERC*, No. 05-1325, slip op. at 13-14 (D.C. Cir. Apr. 13, 2007) ("it is not 'the court's duty to identify, articulate, and substantiate a claim for the petitioner'" in regard to "petitioners' one-sentence cry of protest.").

[23] CT DPUC presented a similar threshold objection to our jurisdiction over ICR in *ISO New England, Inc.*, 111 FERC ¶ 61,185 (2005), *reh'g denied*, 112 FERC ¶ 61,254 (2005). On appeal, the District of Columbia Circuit Court did not address the issue of jurisdiction on the merits, instead remanding the issue to the Commission for an explanation of the basis for its jurisdiction. *See Connecticut Department of Public Utility Control v. FERC*, No. 05-1411 (D.C. Cir. Apr. 20, 2007). The Commission will act on the remand at a later time. Here, though, we address the issue of our jurisdiction and, as explained elsewhere in this order, affirm our jurisdiction for the same reasons given in other, recent orders for asserting jurisdiction.

resource adequacy jurisdiction with the FPA. FPA section 201(b)(1) confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and sales of electric energy at wholesale in interstate commerce.[24] Further, FPA section 205(a) states that:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.[25]

19. Thus, the FPA confers upon the Commission the responsibility for ensuring that transmission and wholesale power sales rates and charges, including any rule, regulation, practice or contract affecting them, are just and reasonable and not unduly discriminatory.

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[24] 16 U.S.C. § 824(b)(1) (2000).

[25] 16 U.S.C. § 824d(a) (2000). FPA section 206 gives the Commission the ability to review "any rate, charges, or classification" charged by a public utility for any transmission or sale subject to the jurisdiction of the Commission, as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification. . . ." 16 U.S.C. § 824e(a) (2000).

20. In *Mississippi Industries v. FERC*,[26] the court recognized the connection between the allocation of capacity and wholesale rates. In that proceeding, the Commission had altered the allocation of capacity and costs of a nuclear generation plant among operating companies of an integrated utility system. Petitioners asserted that, in allocating the cost and capacity of the nuclear plant, the Commission had asserted jurisdiction over generating facilities in direct violation of the FPA section 201(b) prohibition against Commission regulation of generating facilities. Petitioners asserted that "reallocating generation costs falls outside of FERC's rate making jurisdiction and instead falls solely within state authority over generation."[27] The court rejected the claim that this action was beyond the Commission's FPA jurisdiction. Instead, it found that the Commission has authority over the allocation of capacity among market participants because this allocation affects wholesale rates. The court stated, "[c]apacity costs are a large component of wholesale rates" and therefore the share of the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy.[28] While the allocation of capacity did not set sales prices, it directly affects costs and "consequently, wholesale

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[26] 808 F.2d 1525 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1987) (*Mississippi Industries*).

[27] *Id.*, at 1543.

[28] *Id.*, at 1541.

rates"[29] and therefore "FERC's jurisdiction under such circumstances is unquestionable."[30] The court further noted that:

> Petitioners ignore the critical point here that, while these provisions [allocating capacity] do not fix wholesale rates, their terms do directly and significantly *affect* the wholesale rates at which the operating companies exchange energy, due to the highly integrated nature of the . . . system.[31]

21. Similarly, in *Municipalities of Groton v. FERC*,[32] the court upheld the Commission's authority to review section 9.4(d) of the New England Power Pool Agreement which included a deficiency charge for each participant in the agreement whose prescribed level of generating capacity, known as "capability responsibility," fell by more than one percent below the set level. The court found that these charges are within Commission jurisdiction because they are under "the Commission's inclusive jurisdictional mandate – which reaches discriminatory practices 'with respect to' jurisdictional transmissions, or

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[29] *Id.*

[30] *Id.* (*citing Nantahala Power & Light Co.*, 426 U.S. 953 (1986)).

[31] *Id.*, at 1542.

[32] 587 F.2d 1296, 1300 (D.C. Cir. 1978) (*Groton*).

'affecting' such transmissions or services. . . ."[33] The court further stated:

> [i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge. This is well within the Commission's authority as delineated in other court opinions.[34]

22. The Commission likewise has since addressed this question as it involves resource adequacy in New England.[35] Specifically, in *ISO New England, Inc.*,[36] the CT DPUC argued that, while the Commission has the authority to establish the price of capacity or how capacity requirements will be allocated among LSEs, it does not have the jurisdiction to dictate the amount of ICRs that must be purchased. The Commission found that it has jurisdiction to consider the proposed mechanism for the determination of ICR. The Commission explained that the FCM settlement "establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the

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[33] *Id.*, at 1302.

[34] *Id.* (*citing, e.g., FPC v. Conway Corp.*, 426 U.S. 271 (1976)).

[35] *See ISO New England, Inc.*, 111 FERC ¶ 61,185 (2005), *reh'g denied*, 112 FERC ¶ 61,254 (2005).

[36] 118 FERC ¶ 61,157 (2007).

prices for those sales, bringing it squarely within the Commission's jurisdiction under the FPA."[37]

23. We find here, as we did in the ISO-NE Order,[38] that the ICR is one of the principal determinants of the price of capacity and, therefore, falls within the Commission's jurisdiction to review "any rate, charge or classification" charged by a public utility for electric transmission or sales subject to Commission jurisdiction, and "any rule, regulation, practice, or contract affecting such rate, charge or classification."[39] ISO-NE's mechanism to determine ICRs is a "practice . . . affecting" the price of capacity, and as such falls within the Commission's jurisdiction.

24. We find that maintaining adequate resources has a significant and direct effect on jurisdictional rates and services and therefore falls within the Commission's jurisdiction. This finding is fully consistent with *Mississippi Industries* and *Groton*. In *Mississippi Industries*, the Commission exercised jurisdiction over the allocation of the capacity of a nuclear generating plant, despite the fact that the FPA does not give the Commission jurisdiction over generating facilities (and indeed reserves that jurisdiction to the states).[40] The court affirmed Commission jurisdiction because of the nexus between the

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[37] *Id.*, at P 15, 16-21.

[38] *Id.*, at P 15, 19-20.

[39] 16 U.S.C. § 824e(a) (2000).

[40] *Mississippi Industries*, 808 F.2d, at 1543-44.

allocation of capacity and the justness and reasonableness of jurisdictional rates under the Entergy System Agreement. The court in *Groton* undertook a similar analysis in upholding Commission jurisdiction in that case. In *Groton*, the Commission had asserted jurisdiction over a charge related to resource adequacy requirements in New England. The court upheld the Commission's order, finding that that charge affected jurisdictional rates and that jurisdiction remained "irrespective of the objective underlying that charge."[41]

25. We also note that in *California Independent System Operator Corporation*,[42] the Commission addressed how the minimum resource adequacy requirements set forth in the Market Redesign and Technology Upgrade (MRTU) Tariff have an effect on jurisdictional rates and services. The Commission explained that:

> where an interconnected transmission system is operated on [a] regional basis as part of an organized market for electricity, as in California, all users of the system are interdependent, particularly with respect to reliability, *i.e.*, one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must

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[41] *Groton*, 587 F.2d 1296, at 1302.

[42] 116 FERC ¶ 61,274, at P 1113 (2006) (CAISO Order), *reh'g*, 119 FERC ¶ 61,076 (2007) (CAISO Rehearing Order).

> bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory.[43]

26. We further note that ISO-NE has bid caps, and, in the CAISO Order, the Commission found in connection with California's energy market that minimum resource adequacy requirements have a direct nexus to bid caps:

> These bid caps are premised on the notion that bids above these levels may not reflect true scarcity pricing, but rather the exercise of market power or abuse that results in rates that are not just and reasonable. This premise is only valid, however, if there is some mechanism – other than energy price increases – to encourage the construction of new generation where and when needed. Consequently, in the absence of a workable resource adequacy program, it would be difficult for us to approve such bid caps. Without a workable program, the bid caps would simply inhibit new supply, and thereby harm customers, rather than protecting

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[43] *Id.*, at P 1113.

customers from the exercise of market power or abuse.[44]

27. We further note that in the CAISO Order the Commission has addressed the jurisdictional issue that CT DPUC raises here,[45] where the Commission recognized the importance of resource adequacy requirements in meeting our statutory mandate under the FPA to ensure that the rates, terms and conditions of jurisdictional and transmission sales of electric energy in CAISO markets are just, reasonable and not unduly discriminatory or preferential.[46] We also found that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory or preferential.[47]

28. Most recently, in the CAISO Rehearing Order, we reaffirmed our finding on jurisdiction.[48] We found

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[44] *Id.*, at P 1114.

[45] CAISO Order, 116 FERC ¶ 61,274, at P 1112.

[46] *Id.*, 16 U.S.C. §§ 824d and 824e (2000).

[47] *Cal. Indep. Sys. Operator Corp.*, 115 FERC ¶ 61,172, at P 36-37 (2006), *rehearing*, 118 FERC ¶ 61,045 (2007); *see also Gainesville Utils. Dep't v. Fla. Power Corp.*, 402 U.S. 515, 529 (1979) (the Commission has the "responsibility to the public to assure reliable efficient electric service").

[48] *See* CAISO Rehearing Order, 119 FERC ¶ 61,076, at P 521-64; *accord, New York State Reliability Council*, 118 FERC ¶ 61,179, at P 31 (2007), *reh'g pending*.

that the adequacy of resources can have a significant effect on jurisdictional rates and services and, therefore, is subject to Commission jurisdiction. We again found that the FPA confers upon the Commission the responsibility for ensuring that jurisdictional rates and charges – including any rule, regulation, practice or contract affecting them – are just and reasonable and not unduly discriminatory or preferential.[49]

29. We did agree however that, as a general matter, a state or region may determine in the first instance the appropriate level of planning reserves by balancing reliability and cost considerations. Citing the CAISO Order, we noted that "it is our responsibility to ensure that a workable resource adequacy requirement exists in a market such as that operated by the CAISO. This does not mean that we must determine all the elements of such a program in the first instance. Rather, we can, in appropriate circumstances, defer to state and Local Regulatory Authorities to set those requirements. . . ."[50]

30. Therefore, we find that the Commission has jurisdiction to consider and accept ISO-NE's ICRs.

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[49] *Id.*, 16 U.S.C. §§ 824d-824e (2000).

[50] CAISO Rehearing Order, 119 FERC ¶ 61,076, at P 558 (*citing* CAISO Order, 116 FERC ¶ 61,274, at P 1117).

The Commission orders:

The Commission hereby accepts ISO-NE's ICRs, effective May 22, 2007, as discussed in the body of this order.

By the Commission.

(SEAL)

Kimberly D. Bose,
Secretary.

APPENDIX F

121 FERC ¶ 61,125
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners:

Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

ISO New England Inc. Docket No. ER07-655-001

ORDER DENYING REHEARING

(Issued November 1, 2007)

1. In this order, the Commission denies the Connecticut Department of Public Utility Control's (CT DPUC) request for rehearing of a Commission order granting ISO New England Inc.'s (ISO-NE) Power Year 2007/2008 Installed Capacity Requirements (ICR) for the New England Control Area.[1] In the 2007/2008 Power Year ICR Order, the Commission found that it had jurisdiction over ICR and accepted the filing over the objection of the CT DPUC.[2]

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[1] *ISO New England Inc., et al.*, 119 FERC ¶ 61,161 (2007) (2007/2008 Power Year ICR Order).

[2] This docket is one of three in which the CT DPUC raises this jurisdictional argument. Each of the three dockets, ER05-715-002, ER07-365-002, and the instant docket, is at a different procedural stage. Docket No. ER05-715-002, the 2005/2006 Power Year ICR Proceeding, was remanded by the D.C. Circuit Court of Appeals and is currently pending before the Commission. Docket No. ER07-365-002, which involves revisions to

(Continued on following page)

Background

2. On March 23, 2007, ISO-NE submitted for filing its 2007/2008 Power Year ICR,[3] which the Commission accepted for filing to be effective May 22, 2007. ISO-NE explained that it will use the 2007/2008 Power Year ICR values to calculate the Annual and Monthly Installed Capacity Reserve Margins for use in determining the Unforced Capacity rating of demand resources, other demand resources and New York Power Authority contracts. ISO-NE noted that the 2007/2008 ICR values will not be used for establishing the amount of ICAP to be purchased, as was the case in prior years.

3. ISO-NE provided the basis underlying the 2007/2008 Power Year ICR values and explained that the methodologies for determining the tie benefits and projected load are the same as those used in last year's filing and the Equivalent Demand Forced Outage Rate (EFORd) methodology for measuring

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the ISO-NE tariff concerning the processes and methodologies used to determine the ICR, was addressed in an order denying rehearing issued on September 14, 2007. *See ISO New England, Inc. and New England Power Pool*, 120 FERC ¶ 61,234 (2007) (September 14 Order). And Docket No. ER07-655-001 is addressed in this order.

[3] The 2007/2008 Power Year ICR were filed pursuant to *NSTAR Elec. and Gas Corp. v. New England Power Pool*, 103 FERC ¶ 61,093 (2003) (April 30 Order) and section 205 of the Federal Power Act (FPA) 16 U.S.C. § 824d (2000). A detailed explanation of the methodology undertaken by ISO-NE in setting its 2007/2008 ICR is found in the May 18, 2007 Order.

unit availability for the 2005/2006 and 2006/2007 Power Years has been used.[4] ISO-NE also noted that the ICR values were subsequently considered and approved by both the Reliability Committee and the Participants Committee.[5]

Jurisdiction Over ICR

4. In the 2007/2008 Power Year ICR Order, the Commission found that it has jurisdiction to accept the 2007/2008 ICR.[6] The Commission explained that Federal Power Act (FPA) section 201(b)(1) confers jurisdiction over the transmission of electric energy in

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[4] The EFORd measures the portion of time that a generating unit is in demand, but is unavailable due to forced outages. A generator's ICAP is reduced by its EFORd and by other adjustments in order to determine its UCAP rating, which limits the amount of capacity that it can sell in bilateral contracts or in ISO-NE's capacity market auctions.

[5] ISO-NE notes that under the currently effective Regional Transmission Organization (RTO) arrangements in New England, a 60 percent vote in favor is required for Participants Committee action to support a particular set of ICR values.

[6] As noted, the CT DPUC presented a similar threshold objection to the Commission's jurisdiction over ICR in Docket No. ER05-715-001. *ISO New England, Inc.*, 111 FERC ¶ 61,185 (2005), *reh'g denied*, 112 FERC ¶ 61,254 (2005) (2005/2006 Power Year ICR Order). On appeal, the U.S. Court of Appeals for the District of Columbia Circuit did not address the merits of the jurisdiction argument and instead remanded the issue to the Commission for an explanation of the basis for its jurisdiction. *See Connecticut Department of Public Utility Control v. FERC*, No. 05-1411 (D.C. Cir. Apr. 20, 2007). The CT CPUC immediately moved for rehearing, which was denied by the D.C. Circuit.

interstate commerce, and sales of electric energy at wholesale in interstate commerce.[7] The Commission further noted that FPA section 205(a) confers on the Commission jurisdiction over all rates and charges in connection with the transmission or sale of electric energy and ensuring that all rules and regulations affecting or pertaining to the rates or charges are just and reasonable.[8]

5. The Commission also explained that, in *Mississippi Industries v. FERC*,[9] the D.C. Circuit recognized the connection between the allocation of capacity and wholesale rates. There petitioners asserted that, in allocating the cost and capacity of the nuclear plant, the Commission had asserted jurisdiction over generating facilities in direct violation of the FPA section 201(b) prohibition against Commission regulation of generating facilities. The court rejected the claim that "reallocating generation costs falls outside of [the Commission's] rate making jurisdiction and instead falls solely within state authority over generation"[10] and found that the Commission has authority over

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[7] 16 U.S.C. § 824(b)(1) (2000).

[8] 16 U.S.C. § 824d(a) (2000). FPA section 206 gives the Commission the ability to review "any rate, charges, or classification" charged by a public utility for any transmission or sale subject to the jurisdiction of the Commission, as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification. . . ." 16 U.S.C. § 824e(a) (2000).

[9] 808 F.2d 1525 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1987) (*Mississippi Industries*).

[10] *Id.* at 1543.

the allocation of capacity among market participants because this allocation affects wholesale rates. The court stated "[c]apacity costs are a large component of wholesale rates" and therefore the share of the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy and "[the Commission's] jurisdiction under such circumstances is unquestionable."[11]

6. In the 2007/2008 Power Year ICR Order, the Commission also noted that, in *Municipalities of Groton v. FERC*, the D.C. Circuit upheld the Commission's authority to review section 9.4(d) of the New England Power Pool (NEPOOL) Agreement which included a deficiency charge for each participant in the agreement whose prescribed level of generating capacity, known as "capability responsibility," fell by more than one percent below the set level.[12] The court in *Groton* found that because these charges are under "the Commission's inclusive jurisdictional mandate – which reaches discriminatory practices 'with respect to' jurisdictional transmissions, or 'affecting' such transmissions or services,"[13] they are within Commission jurisdiction.

7. In the 2007/2008 Power Year ICR Order, the Commission also noted that the 2005/2006 Power Year ICR Order similarly addressed the jurisdictional

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[11] *Id.* at 1543.

[12] 587 F.2d 1296, 1300 (D.C. Cir. 1978) (*Groton*).

[13] *Id.* at 1302.

question as it involves resource adequacy in New England. Furthermore, in *ISO New England, Inc.*, the Commission found that it has jurisdiction to consider the mechanism for the determination of ICR.[14] The Commission explained there that the forward capacity market (FCM) settlement "establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales, bringing it squarely within the Commission's jurisdiction under the FPA."[15]

8. The Commission also noted that, in *California Independent System Operator Corporation,*[16] the Commission determined that the minimum resource adequacy requirements set forth in the Market Redesign and Technology Upgrade (MRTU) Tariff have an effect on jurisdictional rates and services.[17] The Commission noted that ISO-NE has bid caps, and, in the CAISO Order, the Commission found in connection with California's energy market that minimum resource adequacy requirements have a direct nexus to bid caps.[18] The Commission specifically reaffirmed its finding on jurisdiction in the CAISO Rehearing

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[14] 118 FERC ¶ 61,157 (2007) (February 28 Order), *Order Denying Rehearing*, 120 FERC ¶ 61,234 (2007).

[15] *Id.* at P 15, 16-21.

[16] 116 FERC ¶ 61,274, at P 1113 (2006) (CAISO Order), *reh'g*, 119 FERC ¶ 61,076 (2007) (CAISO Rehearing Order).

[17] *Id.* at P 1113.

[18] *Id.* at P 1114.

Order.[19] The Commission found that the adequacy of resources can have a significant effect on jurisdictional rates and services and, therefore, it is subject to the Commission's jurisdiction. The Commission again found that the FPA confers upon the Commission the responsibility for ensuring that jurisdictional rates and charges – including any rule, regulation, practice or contract affecting them – are just and reasonable and not unduly discriminatory or preferential.[20]

9. In the 2007/2008 Power Year ICR Order the Commission applied the reasoning articulated by the D.C. Circuit and earlier Commission decisions. The Commission found the ICR is one of the principal determinants of the price of capacity and, therefore, falls within the Commission's jurisdiction to review "any rate, charge or classification" charged by a public utility for transmission or sales subject to Commission jurisdiction, and "any rule, regulation, practice, or contract affecting such rate, charge or classification."[21] The Commission reasoned that maintaining adequate resources has a significant and direct effect on jurisdictional rates and services and therefore falls within the Commission's jurisdiction.

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[19] *See* CAISO Rehearing Order, 119 FERC ¶ 61,076, at P 521-64; *accord, New York State Reliability Council*, 118 FERC ¶ 61,179 at P 31 (2007), *reh'g pending*.

[20] *Id.*; 16 U.S.C. §§ 824d-824e (2000).

[21] *Citing, Id.* at P 15, 19-20; *see also* 16 U.S.C. § 824e(a) (2000).

The Commission determined that that finding was fully consistent with *Mississippi Industries, Groton* and the CAISO Rehearing Order.

10. The Commission added that, as a general matter, a state or region may determine in the first instance the appropriate level of planning reserves by balancing reliability and cost considerations. Citing the CAISO Order, the Commission noted that "it is our responsibility to ensure that a workable resource adequacy requirement exists in a market such as that operated by the CAISO. This does not mean that we must determine all the elements of such a program in the first instance. Rather, we can, in appropriate circumstances, defer to state and Local Regulatory Authorities to set those requirements. . . .".[22] The Commission therefore found it has jurisdiction to consider and accept ISO-NE's ICR.

Discussion

Procedural Matters

11. The CT DPUC filed the instant request for rehearing on June 18, 2007. Richard Blumenthal, Attorney General for the State of Connecticut (Connecticut Attorney General) filed an untimely motion to intervene and request for rehearing. Mystic Development, LLC, Mystic I, LLC and Fore River

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[22] CAISO Rehearing Order, 119 FERC ¶ 61,076, at P 558 (*citing* CAISO Order, 116 FERC ¶ 61,274, at P 1117).

Development, LLC (collectively Mystic) filed a motion to intervene and motion to intervene out of time and Millennium Power Partners, L.P. filed a motion to intervene out of time. Milford Power Company, LLC (Milford), ISO-NE, and NEPOOL, filed motions for leave to answer and answers. NEPOOL filed an opposition to the Connecticut Attorney General's filing. The Massachusetts Attorney General and Massachusetts Department of Public Utilities (MA DPUC) filed a motion for leave to file comments and comments. The Connecticut Attorney General filed a motion for leave to file an answer and answer to NEPOOL. Finally, the CT DPUC filed a response to the motions to answer filed by ISO-NE, NEPOOL and Milford.

12. Rule 713 (d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d), prohibits an answer to a request for rehearing. We therefore reject the answers of Milford, ISO-NE, and NEPOOL and the comments of Massachusetts Attorney General and MA DPUC. We will likewise reject the CT DPUC's response.

13. When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for granting such late intervention.[25] Mystic

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[25] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 102 FERC ¶ 61,250, at P7 (2003).

and Millennium have not met this higher burden of justifying their late interventions. Accordingly, we deny their motions to intervene out-of-time.

14. With regard to the Connecticut Attorney General's untimely request for rehearing, filed on June 25, 2007, pursuant to section 313(a) of the FPA, 16 U.S.C. § 825 *l*(a) (2000), an aggrieved party must file a request for rehearing within thirty days after the issuance of the Commission's order – in this case no later than June 17, 2007. Because the 30-day rehearing deadline is statutory, it cannot be extended, and the Connecticut Attorney General's request for rehearing must be rejected as untimely. Moreover, the courts have repeatedly recognized that the time period within which a party may file an application for rehearing of a Commission order is statutorily established at 30 days by section 313(a) of the FPA and that the Commission has no discretion to extend that deadline.[24] Accordingly, we will reject the opposition of NEPOOL to the untimely request for rehearing and to motion to intervene of the Connecticut Attorney General.

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[24] *See City of Campbell v. FERC*, 770 F.2d 1180, 1183 (D.C. Cir. 1985) ("the 30-day time requirement of the [FPA] is as much a part of the jurisdictional threshold as the mandate to file for a rehearing"); *Boston Gas Co. v. FERC*, 575 F.2d 975, 977-78, 979 (1st Cir. 1978).

Discussion of CT DPUC Arguments

15. The CT DPUC argues that the FPA does not give the Commission jurisdiction to accept or approve ISO-NE's proposed Power Year 2007/2008 ICR and in fact, the FPA expressly and unambiguously reserves to the states jurisdiction over facilities used for generating electricity and resource adequacy decisions.[25]

16. The CT DPUC acknowledged that the jurisdictional issue is before the Commission in two other parallel cases and it moved to make this proceeding the vehicle for accepting all comments and arguments regarding the issue.[26]

17. We remain unpersuaded by the CT DPUC's arguments regarding the Commission's jurisdiction over ICR. We therefore deny rehearing. We also note that the CT DPUC seeks to raise arguments concerning issues that fall outside of the 2007/2008 Power Year ICR Order.[27] Those issues are more appropriately

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[25] CT DPUC Rehearing Request at 10 (*citing* 18 C.F.R. § 385.713 (2006)).

[26] Joint Motion by the CT DPUC, NEPOOL, and ISO-NE to Establish a Briefing and Procedural Schedule and Request for Expedited Action, *ISO New England Inc. et al.*, Dockets Nos. ER05-715-002, ER07-365-002, ER07-655-000 (June 6, 2007).

[27] *See* CT DPUC Rehearing Request at 2 ("In order to give the Commission a comprehensive analysis of the jurisdictional questions that the CT DPUC has raised, this request will address each of the Commission's asserted basis for setting ICR, *even if it was not expressly discussed in the May 18 Order*") (emphasis added).

raised in the related dockets. We will therefore only address those errors the CT DPUC claims that concern the 2007/2008 Power Year ICR Order.

18. As stated in the February 28 Order, contrary to arguments made by the CT DPUC, the Commission asserted jurisdiction not over generating facilities, but over "an essential component of the charge for wholesale capacity in interstate commerce".[28] The Commission was not requiring that any state build generation, or that any participant satisfy its capacity obligation via a particular resource.

19. The Commission stated that its responsibility to assure that wholesale rates are just and reasonable does not mean that it cannot, when appropriate, accept state determinations regarding resource adequacy requirements, noting that in the CAISO proceeding it had found that it could, in appropriate circumstances, defer to state and local regulatory authorities to set resource requirements.[29] The Commission also pointed out, however, that there was currently no proposal from all the New England states under consideration.

20. Thus, the Commission stated, "we therefore act today to establish an integral component of the jurisdictional charge for wholesale capacity within

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[28] February 28 Order at P 20.

[29] *Id.* at P 21 (*citing CAISO Order*, 116 FERC ¶ 61,274, at P 1117).

New England to ensure that wholesale rates are just, reasonable and not unduly discriminatory."[30]

Commission Jurisdiction Under the FPA

CT DPUC Argument

21. According to the CT DPUC, the FPA makes clear that states retain their traditional authority over the determination of resource adequacy requirements, particularly when that determination bears directly on the amount of generating facilities that a state must provide.[31] The CT DPUC states that Congress recognized that states are particularly well suited to evaluate the need for additional capacity resources and to determine the conditions for satisfying that demand and that Congress emphasized that federal regulation "extend[s] only to those matters which are not subject to regulation by the States."[32] The CT DPUC argues that this Congressional declaration should be respected. It also asserts that states have long regulated all aspects of resource adequacy and generating facilities, and there is no basis in the FPA or otherwise for disrupting this Congressionally-dictated allocation of responsibility.[33] The CT DPUC

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[30] *Id.*

[31] CT DPUC Rehearing Request at 13.

[32] *Id.* (*citing* 16 USC § 824(a) (2000)).

[33] *Id.* at 14-15. CT DPUC argues that Congress reiterated this reservation of authority to the states in section 201(b)(1), stating:

(Continued on following page)

then states that the New England states themselves have developed resource adequacy plans for their utilities using the same reliability standards as the Commission (and thus producing, in the aggregate, a region-wide ICR); thus, the CT DPUC argues that there can be more than one technically acceptable solution to the question of how much capacity the New England region should purchase, and states' exercise of their authority to set resource adequacy levels will not interfere with any Commission goals.[34]

22. The CT DPUC disputes the Commission's statement that, by setting ICR, it "is not asserting jurisdiction over generating facilities." It points to the fact

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> [t]he Commission shall have jurisdiction over all facilities for [the transmission of electric energy in interstate commerce] or [the sale of electric energy at wholesale in interstate commerce], but shall not have jurisdiction, except as specifically provided in this Part and the Part next following, over facilities used for the generation of electric energy . . . ;

and in section 207, stating:

> even when a state commission complains about inadequate or insufficient interstate service, "the Commission shall have no authority to compel the enlargement of generating facilities" for the purpose of furnishing "proper, adequate, or sufficient service;" and

in section 215:

> the Commission's authority to set reliability standards "does not include any requirement to . . . construct new . . . generation capacity."

[34] CT DPUC Rehearing Request at 2-4.

that the majority of ISO-NE's capacity resources are generating facilities rather than demand response or other resources.[35] The CT DPUC considers irrelevant the Commission's argument that a state can satisfy its capacity obligation in many ways, when virtually all of those methods result in the necessity for a specified quantity of generating facilities that must be available within the state or region.[36] It also states that, as load grows, the only resources that can provide incremental kilowatt hours of energy are generators.[37]

23. The CT DPUC argues that the most fundamental aspect of a state's jurisdiction over generating facilities is its authority to determine how much generating capacity is required, which decision has ramifications for all other aspects of state regulation and control over generating facilities.[38] As an example, the CT DPUC argues that, because optimal locations for generating facilities – *e.g.*, with the requisite access to fuel, water, transmission, and proximity to load – are scarce, if the Commission sets

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[35] *Id.* at 14. The CT DPUC states that ISO-NE's most recent assessment of available capacity resources in New England found 30,526 MW of summer capacity consisting of combined cycle, fossil, nuclear, hydro, jet, and diesel generating facilities, and only 580 MW of demand response. CT DPUC Rehearing Request at 15, *citing* ISO-NE's "Proposed Installed Capacity Requirements for 2007-2008".

[36] CT DPUC Rehearing Request at 11.

[37] *Id.*

[38] *Id.*

ICR at a level above what a state believes is necessary for reliability, that state may be required to (a) identify and approve additional sites where generation can be built, even if they are unsuitable or do not comport with the state's overall land use plans, (b) grant clean air waivers, (c) keep environmentally hazardous or undesirable units in service when they should be retired, or (d) forego the development of longer lead time, base load generating facilities – *e.g.*, a new nuclear power plant – because it must instead add a succession of new peaking units each year to satisfy the annual ICR.[39] The CT DPUC argues that, when the Commission sanctions ISO-NE's mechanism to set the level of ICR, it compels states to supply ISO-NE's projection of the minimum amount of capacity necessary to reliably serve load, and under the FCM, load serving entities (LSEs) in each state must acquire their proportionate share of ICR at the Forward Capacity Auction clearing price. Thus, the CT DPUC argues, the Commission's approval of ICR also dictates the amount of capacity that must be installed in each capacity zone. The CT DPUC states that "[b]y setting ICR, the Commission effectively strips the states of their FPA-protected control over generating facilities within their borders."[40]

24. The CT DPUC further argues that the Commission erred in its assertion that the ICR is one of the

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[39] *Id.* at 11-12.

[40] CT DPUC Rehearing Request at 16-17.

principal determinants of the price of capacity.[41] It states that the FCM provides that the Capacity Clearing Price will be set by new capacity, not existing capacity, that the Commission has taken pains to distinguish between the mechanism for setting ICR and the mechanism for setting the capacity price, and that in the FCM, the ICR is "no more than a plug-in number in the rate formula."[42] The CT DPUC states that while the FCM requires load serving entities to purchase their proportionate share of ICR, how the ICR is set or by whom are not integral parts of the FCM, and the only role that the ICR has in the capacity charge is to provide the quantity multiplier in computing the total amount that load serving entities pay.

Commission Ruling

25. At the outset, it is important to note that section 201(b)(1) of the FPA confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and sales of electric energy at wholesale in interstate commerce.[43] Further, FPA section 205(a) states that:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of

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[41] *Id.* at 18.

[42] *Id.* at 19.

[43] 16 U.S.C. § 824(b)(1) (2000).

> electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.[44]

26. Accordingly, the FPA confers upon the Commission the responsibility for ensuring that transmission and wholesale power sales rates and charges, including any rule, regulation, practice or contract affecting them, are just and reasonable and not unduly discriminatory or preferential. And, given that the ICR is one of the principal determinants of the price of capacity, review of the determination of the ICR rests with the Commission. In this regard, as described above, the ICR directly affects the capacity clearing price and charges to customers. The purpose of the Forward Capacity Auction is to determine the price at which the amount of capacity offered by all New England capacity resources equals the ICR (i.e., equals what is essentially demand); that price becomes the price of capacity, which, in turn, is charged to customers. The "stopping point" of this "descending clock" auction is therefore directly influenced by the

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[44] 16 U.S.C. § 824d(a) (2000). FPA section 206 similarly gives the Commission the ability to review "any rate, charges, or classification" charged by a public utility for any transmission or sale subject to the jurisdiction of the Commission, as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification. . . ." 16 U.S.C. § 824e(a) (2000).

size of the ICR (i.e., essentially demand): a greater ICR (i.e., essentially greater demand) will typically result in a higher price of capacity (i.e., a higher clearing price) and higher charges to customers, while a lesser ICR (i.e., essentially lesser demand) will typically result in a lower price of capacity (i.e., a lower clearing price) and lower charges to customers.

27. Turning to the specifics of the CT DPUC's arguments, as the CT DPUC states, in the FPA, Congress did not grant the Commission authority over electrical generating capacity. Contrary to the CT DPUC's claim, however, the Commission is not exercising authority over electrical generating capacity or setting the amount of generating capacity that states must build (or require to be built) within their borders. Rather, the Commission is reviewing the means by which ISO-NE determines how much capacity its member LSEs must provide (which leads ultimately to a determination of how much capacity each state's LSEs must provide), which, as described above, directly affects the charges to customers, in order to evaluate the justness and reasonableness of the resulting rates and charges for those capacity obligations.

28. It is also critical to distinguish between ISO-NE's "capacity" requirement and "electrical generating capacity." In essence, "capacity" (the ability to produce electric energy to serve load, when called by ISO-NE) is the product, and electrical generating capacity is one means, but not the only means, of producing that product. For example, assume that

within a particular state, ISO-NE determines that an LSE must provide 100 MW of capacity (in addition to the capacity that the LSE currently has). This does not mean that the LSE must necessarily construct, and the state must permit the construction of, 100 MW of new electrical generating capacity. The LSE could fulfill its capacity obligation to ISO-NE by constructing new electrical generating capacity but it could also add 50 MW of demand response[45] and 50 MW of capacity contracts (from inside or outside the state), or any mix of the above. If a state wishes to place controls on the amount or type of electrical generating capacity built within it, or at particular locations within it, the Commission's regulation of ISO-NE's calculation of ICR does not prevent it from doing so.[46] The capacity requirement that ISO-NE places on an individual LSE may be a factor in a state's ultimate determination as to how much electrical generating capacity is built, where and by

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[45] Demand response reduces load to be served, so that less electric generating capacity is needed to serve load.

[46] *See, e.g., Jersey Central Power & Light Company v. Atlantic City Electric Co.*, 111 FERC ¶ 61,179, at P 10, 24-25, 27, *order on reh'g*, 113 FERC ¶ 61,237 at P 6-7, 47-48, 54-58 (2005), *reh'g denied*, 116 FERC ¶ 61,256 at P 13-15 (2006) (complainant sought relief from Commission-jurisdictional contract obligation to build facilities on the basis that, among other things, environmental regulation by the State of New Jersey prevented it from fulfilling its contract obligation; Commission responded that contract already contemplated that facilities might not be built and already provided complainant with options such as construction of other facilities).

whom. These are not, however, the same determinations, and it is inaccurate to conflate the two as the CT DPUC does here.

29. While, as the CT DPUC notes, currently the majority of the New England states' capacity needs are met through electrical generating capacity, this does not mean that that will remain the case in the future. The FCM is, in fact, currently eliciting the development of new resources, which may be electrical generating capacity or demand response providers.[47] Nothing in the ICR requirement prevents a state from requiring its LSEs to meet capacity requirements through demand response, or through contracts to purchase power (from resources located inside or outside the state), or through more environmentally-friendly generation, or, generally speaking, through resources that meet state health or environmental or land-use planning goals. In essence, ISO-NE says to its LSEs, "Provide X amount of resources." But *how* those resources are provided is up to the LSEs and the states.

30. It is, moreover, inaccurate to state, as the CT DPUC does, that the FCM has "decoupled" price and

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[47] The fact that there has been significant interest in providing demand response service can be seen in *ISO New England, Inc.*, 119 FERC ¶ 61,045 (2007), where the Commission required changes to the FCM market rules in response to issues raised by multiple demand response providers to allow them to compete more effectively with electrical generating capacity. *See id.* at P 145-47, 152.

capacity, and that the only effect that the ICR will have on capacity prices will be to provide the number of MWs of capacity that LSEs acquire. Again, as explained above, the ICR has a direct impact on the capacity clearing price in the Forward Capacity Auction. It is true that the price of capacity will be set by the CONE (Cost of New Entry) in those circumstances in which new entry is needed to meet capacity requirements.[48] However, ISO-NE's ruling of how many MWs of capacity each LSE must acquire will determine whether, in fact, new resources will need to be developed to enable LSEs to meet that standard. Further, even in situations where new capacity resources are developed and set the per-MW price, an LSE's total cost for capacity will be the result of (a) the price of each MW, multiplied by (b) the number of MWs the LSE must purchase.

Relevant Caselaw

CT DPUC Argument

31. The CT DPUC also states that, in *Northwest Central Pipeline Corp.* v. *State Corp. Comm'n of Kansas*,[49] the Supreme Court found that a practice

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[48] As described above, in the Forward Capacity Auction all capacity resources submit supply offers at descending price levels, beginning at a price equal to twice the CONE. Where new entry is needed to meet capacity requirements, though, as the cost of new entry is the CONE, the price of capacity will be set by the CONE.

[49] 489 U.S. 493 (1989) (*Northwest Central*).

that merely "affects" rates or charges does not negate the FPA's reservation of jurisdiction over resource adequacy to the states, unless state determination of resource adequacy would prevent attainment of Commission goals – a showing that, the CT DPUC argues, the Commission has not made here. According to the CT DPUC, Congress did not intend that any practice "affecting" rates and charges trumped the reservation of jurisdiction to the states. Rather, the CT DPUC argues, in *Northwest Central* the Court found that, although almost any state regulation of generating facilities could have an impact on wholesale capacity costs, "Congress has drawn a brighter line, and one considerably more favorable to the States' retention of their traditional powers to regulate" the facilities that produce electric energy.[50] Thus, the CT DPUC states, state regulation of generating facilities may be pre-empted only if "state regulation prevents attainment of [the Commission's] goals,"[51] and the Commission has not made such a showing.

32. The CT DPUC argues that the Commission's reliance on *Groton* and *Mississippi Industries*[52] is inapposite. It asserts that *Groton* did not involve a

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[50] CT DPUC Rehearing Request at 21 (*citing Northwest Central* at 514).

[51] CT DPUC Rehearing Request at 22 (*citing Northwest Central* at 515-16).

[52] 808 F.2d 1525, 1542 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1978).

Commission order relating to generating facilities, but rather, the rate that would be charged for a capacity deficiency. The CT DPUC also argues that in *Mississippi Industries* the Commission only acted to remedy discrimination in the allocation of existing capacity costs, but not to establish the amount of capacity that a system would have to acquire. The CT DPUC considers it impermissible to "leap" from such authority over cost allocation to requiring the provision of a particular amount of capacity, since setting ICR is a reliability and resource adequacy question, not a cost allocation question.[53] The CT DPUC further notes that the Commission did not, in *Mississippi Industries*, seek to dictate where or when or how many generating facilities would be built, and that unlike the situation in *Mississippi Industries,* which involved a system in which generating capacity was built on a highly integrated basis, in New England there is no similar integrated system and all decisions about planning and building generation are made by individual market participants. And finally, the CT DPUC notes that *Groton* and *Mississippi Industries* were decided prior to, and have now been superseded by, the Supreme Court's *Northwest Central* decision.

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[53] CT DPUC Rehearing Request at 25.

Commission Ruling

33. The Commission has considered the question of its jurisdiction over capacity requirements set by RTOs many times. As we stated in the 2007/2008 Power Year Order, section 201(b)(1) of the FPA confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and over sales of electric energy at wholesale in interstate commerce, and "all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable."[54] In the 2007/2008 Power Year Order we reaffirmed that the determination of a system's capacity requirement is a "rule or regulation affecting or pertaining to" the charges for the wholesale sale of electric energy in interstate commerce.[55] In response to the CT DPUC's argument that Congress did not intend any practice "affecting" rates and charges to trump the FPA's reservation of jurisdiction over resource adequacy to the states, we note here again that, as discussed in the February 28 Order, we are not considering just any practice affecting rates and charges. Rather, we are looking at what the February

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[54] 2007/2008 Power Year ICR Order at P 18.

[55] *Id.* at P 23 ("the ICR is one of the principal determinants of the price of capacity and, therefore, falls within the Commission's jurisdiction to review 'any rate, charge or classification' charged by a public utility for electric transmission or sales subject to Commission jurisdiction, and 'any rule, regulation, practice, or contract affecting such rate, charge or classification.'").

28 Order characterized as a "principal" determinant of rates and charges.[56]

34. In the 2007/2008 Power Year Order, we further reaffirmed our reliance on the *Mississippi Industries* and *Groton* precedents. First, we noted that, in *Mississippi Industries*, the court had recognized the connection between the allocation of capacity and wholesale rates:

> In that proceeding, the Commission had altered the aliocation of capacity and costs of a nuclear generation plant among operating companies of an integrated utility system. Petitioners asserted that, in allocating the cost and capacity of the nuclear plant, the Commission had asserted jurisdiction over generating facilities in direct violation of the FPA section 201(b) prohibition against Commission regulation of generating facilities. . . . The court rejected the claim that this action was beyond the Commission's FPA jurisdiction. Instead, it found that the Commission has authority over the allocation of capacity among market participants

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[56] *See id.* at P 23 ("the FCM settlement 'establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales, bringing it squarely within the Commission's jurisdiction under the FPA,'" (citation omitted)).

because this allocation affects wholesale rates.[57]

35. We pointed to the court's statements that "[c]apacity costs are a large component of wholesale rates" and therefore the share of the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy,[58] and that while the allocation of capacity did not set sales prices, it directly affects costs and "consequently, wholesale rates."[59] We also cited the court's conclusion that "FERC's jurisdiction under such circumstances is unquestionable"[60] and that "[p]etitioners ignore the critical point here that, while these provisions [allocating capacity] do not fix wholesale rates, their terms do directly and significantly *affect* the wholesale rates at which the operating companies exchange energy, due to the highly integrated nature of the . . . system."[61]

36. In the 2007/2008 Power Year ICR Order we further noted that, in *Groton*, the court upheld the Commission's authority to review a NEPOOL rule requiring that each NEPOOL participant who was

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[57] *Id.* at P 20.

[58] *Id.* (*citing Mississippi Industries* at 1541).

[59] *Id.*

[60] *Id.* (*citing Nantahala Power & Light Co.*, 426 U.S. 953 (1986)).

[61] *Id.* at P 20 (*citing Mississippi Industries* at 1542).

deficient in its capacity requirement pay a deficiency charge. We stated that:

> The court found that these charges are within Commission jurisdiction because they are under "the Commission's inclusive jurisdictional mandate – which reaches discriminatory practices 'with respect to' jurisdictional transmissions, or 'affecting' such transmissions or services. . . ."[62] The court further stated "[i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge. This is well within the Commission's authority as delineated in other court opinions."[63]

37. We then found that "maintaining adequate resources has a significant and direct effect on jurisdictional rates and services and therefore falls within the Commission's jurisdiction."[64] We stated that this finding was fully consistent with *Mississippi Industries* and *Groton*:

> In *Mississippi Industries*, the Commission exercised jurisdiction over the allocation of the capacity of a nuclear generating plant, despite the fact that the FPA does not give

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[62] *Groton* at 1302.

[63] 2007/2008 Power Year ICR Order at P 21 (*citing, e.g., FPC v. Conway Corp.*, 426 U.S. 271 (1976)).

[64] *Id.* at P 24.

> the Commission jurisdiction over generating facilities (and indeed reserves that jurisdiction to the states). The court affirmed Commission jurisdiction because of the nexus between the allocation of capacity and the justness and reasonableness of jurisdictional rates under the Entergy System Agreement. The court in *Groton* undertook a similar analysis in upholding Commission jurisdiction in that case. In *Groton*, the Commission had asserted jurisdiction over a charge related to resource adequacy requirements in New England. The court upheld the Commission's order, finding that that charge affected jurisdictional rates and that jurisdiction remained "irrespective of the objective underlying that charge."[65]

38. Thus, the Commission has previously ruled, and reaffirms here, that ISO-NE's method of determining its ICR (the amount of capacity that its member LSEs must provide) has a sufficiently immediate and direct effect on the rates, terms and conditions of the sale of electric energy in interstate commerce that it falls within the Commission's jurisdiction.

39. The CT DPUC's citation to *Northwest Central* does not assist it. *Northwest Central* speaks to the question of whether a federal agency's regulation of a particular area pre-empts state regulation in that area. This is not the case here. As discussed above,

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[65] *Id.* (*citing Groton* at 1302).

the Commission is not seeking to pre-empt (and has not pre-empted) the state's decision-making as to when or where or how many new (if any) generating facilities should be built in that state, and ISO-NE's determination of the amount of capacity that each LSE must procure does not render the state unable to go through that decision-making process. Thus, there is no pre-emption of state authority of the kind in issue in *Northwest Central*.[66]

Differences between New England and California

CT DPUC Argument

40. The CT DPUC states that, in relying on the CAISO Order to support its exercise of jurisdiction over the ISO-NE method of determining ICR, the Commission ignored differences between the California and New England energy markets. According

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[66] Additionally, assuming *arguendo* that the Commission was in fact preempting state decision-making authority, so that *Northwest Central* did apply, the Commission's actions here would pass the *Northwest Central* test. The CT DPUC asserts that, in *Northwest Central*, the Supreme Court found that a practice that merely "affects" rates or charges does not negate the FPA's reservation of jurisdiction over resource adequacy to the states, unless state determination of resource adequacy would prevent attainment of Commission goals, and that the Commission has not made a showing here that any Commission goal would not be attained. Given the existence of an integrated region-wide system in New England, and given the absence of a region-wide resource adequacy determination process in New England, the Commission has made such a showing.

to the CT DPUC, the Commission pointed to the possibility that one participant's reliability decisions could negatively impact other participants as demonstrating the need for FERC authority over CAISO's resource adequacy determinations.[67] The CT DPUC states that such "free rider" problems (in which one local area could set a lower reserve requirement than necessary, and the utilities in that area would then "lean on" capacity provided in other local areas) will not arise in New England, because the New England states have a long tradition of pooling of capacity resources for the benefit of all parties, and because under the FCM, each local area will have a capacity requirement based specifically on how much capacity is present in and can be imported into that area.

41. The CT DPUC further argues that the Commission's concern with bid caps in California does not justify its exercise of jurisdiction over the New

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[67] CT DPUC Rehearing Request at 27-28 (*citing* 2007/2008 Power Year ICR Order at P 25 (*citing* CAISO Order at P 1113 ("where an interconnected transmission system is operated on a regional basis as part of an organized market for electricity . . . all users of the system are interdependent, particularly with respect to reliability, *i.e.*, one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory")).

England capacity market. In the February 28 Order, the Commission noted that, in approving bid caps to protect against market abuse in energy markets in California, it had found that, unless there were some mechanism (other than increases in the price of energy) to encourage the construction of new generation, such as a robust capacity market, "it would be difficult for us to approve such bid caps [, which] . . . would simply inhibit new supply, and thereby harm customers."[68] The CT DPUC asserts that in New England, however, unlike in California, the FCM's Peak Energy Rent mechanism "is intended to mitigate incentives to create price spikes in the energy market,"[69] so that the bid cap in New England is now, in essence, irrelevant, and the Commission's fear that bid caps will inhibit the construction of new supply is groundless. The CT DPUC also asserts that the FCM provides sufficient incentives to attract new infrastructure where needed.

Commission Ruling

42. Neither of the CT DPUC's arguments here are valid. In the 2007/2008 Power Year ICR Order, we stated that we had addressed precisely this jurisdictional question in the CAISO Order, and noted

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[68] CAISO Order at P 1114, *cited in* 2007/2008 Power Year ICR Order at P 26.

[69] CT DPUC Rehearing Request at 29 (*citing Devon Power LLC*, 115 FERC ¶ 61,340 (2006) (FCM Order) at P 29).

that "the Commission recognized the importance of resource adequacy requirements in meeting our statutory mandate under the FPA to ensure that the rates, terms and conditions of jurisdictional and transmission sales of electric energy in CAISO markets are just, reasonable and not unduly discriminatory or preferential."[70] It is inaccurate to assert, as the CT DPUC does, that the Commission was concerned solely with possible free rider problems. Whether or not the New England LSEs have a practice of pooling capacity resources for the benefit of all, as the CT DPUC states, is irrelevant to the possibility that concerned the Commission – namely, that within a large integrated system such as the New England control area, reliability actions taken by one local area could have an adverse effect on neighboring local areas. This problem can occur even absent any intent to lean on a neighbor's capacity: for instance, a project built to address one state's reliability needs might, because of its location and impact on the interstate transmission system, inadvertently cause reliability problems for a neighboring state. Therefore, as the Commission stated, "in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and

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[70] 119 FERC ¶ 61,161, at P 27.

reasonable and not unduly discriminatory or preferential."[71]

43. Similarly, the CT DPUC's argument that the Commission's reliance on the CAISO Order and CAISO Rehearing Order to support its exercise of jurisdiction over the determination of ICR has been vitiated by the FCM's Peak Energy Rent mechanism is incorrect.[72] The CT DPUC argues that, in those two orders, the Commission supported its assertion of jurisdiction over resource adequacy by pointing to the fact that the Commission had found that, due to the bid caps in the CAISO energy markets, the construction of new supply might be inhibited unless the market design contained some other mechanism to ensure sufficient construction of supply. Here, in contrast, the CT DPUC states, since the Peak Energy Rent mechanism has ensured that New England's bid caps will never be activated, there is no need for the Commission to exercise jurisdiction.

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[71] *Cal. Indep. Sys. Operator Corp.*, 115 FERC ¶ 61,172, at P 36-37 (2006), *order on rehearing*, 118 FERC ¶ 61,045 (2007); *see also Gainesville Utils. Dep't v. Fla. Power Corp.*, 402 U.S. 515, 529 (1979) (the Commission has a "responsibility to the public to assure reliable efficient electric service").

[72] The Peak Energy Rent mechanism seeks to stabilize prices by deducting from capacity prices amounts that might hypothetically be earned in the energy market during price spikes. *See* FCM Order at P 29 ("the peak energy rent deduction is intended to help mitigate incentives to create price spikes in the energy market [because it] will remove any profits gained from the rise in prices because the extra revenues earned in the energy market are deducted from capacity payments").

44. This argument mistakes the nature of the Commission's concerns in the CAISO Order and CAISO Rehearing Order. We stated there:

> [R]esource adequacy plays an important role in addressing whether Commission-jurisdictional wholesale prices reflect the exercise of market power or the scarcity of supply. In particular, we are approving bid caps for the markets operated pursuant to the [Market Redesign and Technology Upgrade] Tariff. These bid caps are premised on the notion that bids above these levels may not reflect true scarcity pricing, but rather the exercise of market power or abuse that results in rates that are not just and reasonable. This premise is only valid, however, if there is some mechanism – other than energy price increases – to encourage the construction of new generation where and when needed. Consequently, in the absence of a workable resource adequacy program, it would be difficult for us to approve such bid caps. Without a workable program, the bid caps would simply inhibit new supply, and thereby harm customers, rather than protecting customers from the exercise of market power or abuse.[73]

45. The Commission focused on the fact that, in approving California's tariff provisions (which are clearly within the Commission's jurisdiction), we had

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[73] CAISO Order at P 1114.

put into place a market design that contained an element that could, potentially, inhibit the construction of necessary new generation and ultimately harm electricity customers. Thus, it was critical that the Commission be able to ensure that the market design also included a countervailing mechanism to ensure the construction of new capacity resources – in this case, a capacity market that sent appropriate price signals to encourage the development of new capacity. Absent the power to ensure that capacity prices correctly reflect the value of capacity, so as to make sure that necessary capacity is provided to the system, the Commission could not have approved a market design that included bid caps. This is equally true in New England, where the market design similarly contains bid caps; whether the Peak Energy Rent mechanism will modulate energy price spikes to a sufficient degree to render those bid caps irrelevant is an as-yet-untested proposition.

Deference to New England States

CT DPUC Argument

46. The CT DPUC states that, despite paying "lip service" to the concept of respecting state decision-making with respect to resource adequacy, the Commission has failed to do so and now asserts that it retains absolute jurisdiction to override any state's resource adequacy determination. The CT DPUC states that it has proposed a specific mechanism under which the states would determine ICR, based

on information provided by ISO-NE. The CT DPUC states that, on rehearing, the Commission should either reject ISO-NE's proposed ICR rules as beyond the Commission's jurisdiction to accept, or impose and direct ISO-NE to file rules that reflect the CT DPUC's proposal.

Commission Ruling

47. In the 2007/2008 Power Year ICR Order, the Commission reiterated that

> as a general matter, a state or region may determine in the first instance the appropriate level of planning reserves by balancing reliability and cost considerations. Citing the CAISO Order [in the CAISO Rehearing Order], we noted that "it is our responsibility to ensure that a workable resource adequacy requirement exists in a market such as that operated by the CAISO. This does not mean that we must determine all the elements of such a program in the first instance. Rather, we can, in appropriate circumstances, defer to state and Local Regulatory Authorities to set those requirements."[74]

48. The Commission has not changed its view. However, the CT DPUC does not point to a completed and ready-to-implement program for determining

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[74] 2007/2008 Power Year ICR Order, 119 FERC ¶ 61,161, at P 29 (*citing* CAISO Rehearing Order, 119 FERC ¶ 61,076, at P 558 (citation omitted)).

capacity requirements by the states. Rather, the CT DPUC points to a proposal filed in June 2004 by the New England governors. On July 7, 2005, the Commission issued an order deferring action, and encouraging further discussion among the stakeholders.[75] And in its most recent status report on the proposal, filed on July 13, 2007, ISO-NE stated that it has prepared Schedule 5 to its tariff which is intended to be the vehicle for funding NESCOE, which was approved at a July 6 meeting of the NEPOOL Participants Committee.[76] As a result, as the Commission stated in the February 28 Order, "[t]here is no agreement among the New England states to establish the ICR and therefore nothing to which we could defer."[77] That situation has not changed. Thus, NESCOE is still in the process of formation, rather than being an organization that is fully capable, at this time, of making resource adequacy determinations. Accordingly, CT DPUC has raised no basis to grant rehearing.

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[75] *Governors of: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont*, 112 FERC ¶ 61,049 (2005).

[76] On August 31, 2007, in Docket No. ER07-1324-000, ISO-NE, NEPOOL and the state parties made a filing concerning Schedule 5. A decision in Docket No. ER07-1324-000 is currently pending.

[77] February 28 Order at P 21.

The Commission orders:

The Commission hereby denies the CT DPUC's request for rehearing, as discussed above.

By the Commission.

(SEAL)

Nathaniel J. Davis, Sr.,
Acting Deputy Secretary.

APPENDIX G

122 FERC ¶ 61,144
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman; Suedeen G. Kelly, Marc Spitzer, Philip D. Moeller, and Jon Wellinghoff.

ISO New England, Inc. Docket No. ER05-715-002

ORDER ON REMAND

(Issued February 21, 2008)

1. In this order on remand, we explain the basis for the Commission's jurisdiction over the filing at issue in this proceeding – ISO New England, Inc.'s (ISO-NE) Power Year 2005/2006 Installed Capacity Requirements (ICR) for the New England Control Area.

Background

2. For over 20 years, ISO-NE has imposed ICRs on its members in order to maintain adequate system reliability.[1] The ICR is a projection of the minimum amount of capacity required to serve load reliably in

[1] Prior to the existence of the ISO-NE the requirements were imposed on the members of the New England Power Pool (NEPOOL), and the ICR was then called NEPOOL's Objective Capability (OC).

the New England region. The ICR is used to determine the monthly unforced capacity (UCAP) requirements (with various adjustments) that each market participant must purchase. ISO-NE calculates the ICR to meet system design criteria with a Loss of Load Expectation of one day in ten years. To meet their UCAP obligations, market participants must self-supply, purchase UCAP through bilateral transactions, or obtain capacity credits from tie-line benefits, or they must make up any deficiencies in the ISO-NE administered installed capacity market. The ICR directly affects the determination of the clearing price in the capacity market and so affects the charges to customers. If a market participant does not have or acquire sufficient capacity, it must pay a deficiency rate.

3. On March 21, 2005, as supplemented on April 1, 2005, ISO-NE filed its ICR for the 2005/2006 Power Year. The Connecticut Department of Public Utility Control (CT DPUC) protested the substance of the ICR and also argued that the Commission does not have jurisdiction to regulate resource adequacy, a matter the CT DPUC argued that the Federal Power Act (FPA) leaves to the states. The Commission accepted ISO-NE's 2005/2006 Power Year ICR with modifications.[2] On appeal, the U.S. Court of Appeals for the District of Columbia Circuit, without

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[2] *ISO New England, Inc.*, 111 FERC ¶ 61,185, *reh'g denied*, 112 FERC ¶ 61,254 (2005).

addressing the merits, remanded the issue of jurisdiction to the Commission for an explanation of the basis for the Commission's jurisdiction.[3]

4. The CT DPUC has raised the same argument, that the Commission lacks jurisdiction over ICR, in response to two other relatively recent ISO-NE filings. The first of those proceedings involved ISO-NE's filing a tariff change to revise the processes and methodologies used to determine ICR. In response to that filing the Commission accepted the tariff changes and explained the basis of its jurisdiction.[4] The CT DPUC has appealed that decision.[5] The second of those proceedings involved ISO-NE's filing its ICR for the 2007/2008 Power Year. The Commission accepted the ISO-NE's 2007/2008 Power Year ICR, and again explained the basis of its jurisdiction.[6] The CT DPUC has also appealed that decision.[7] Consistent with the orders in those two proceedings, and as discussed below, the Commission finds that it has jurisdiction over the ICRs.

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[3] *Connecticut Department of Public Utility Control v. FERC*, 484 F.3d 558 (D.C. Cir. 2007).

[4] *ISO New England, Inc.*, 118 FERC ¶ 61,157, *reh'g denied*, 120 FERC ¶ 61,234 (2007).

[5] *Connecticut Department of Public Utility Control v. FERC*, No. 07-1375 (D.C. Cir. filed September 19, 2007).

[6] *ISO New England, Inc.*, 119 FERC ¶ 61,161, *reh'g denied*, 121 FERC ¶ 61,125 (2007).

[7] *Connecticut Department of Public Utility Control v. FERC*, No. 07-1460 (D.C. Cir. filed November 13, 2007).

Discussion

5. The CT DPUC asserts that the Commission does not have jurisdiction to establish ICRs. The CT DPUC argues that the FPA expressly directs that the Commission "shall not have jurisdiction . . . over facilities used for the generation of electric energy." The CT DPUC argues that, while the Commission has the authority to establish the price of capacity and how capacity requirements will be allocated among load serving entities, it does not have jurisdiction to dictate the amount of ICR that must be purchased.

6. We begin our analysis of the Commission's resource adequacy jurisdiction with the FPA. FPA section 201(b)(1) confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and sales of electric energy at wholesale in interstate commerce.[8] Further, FPA section 205(a) states that:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and

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[8] 16 U.S.C. § 824(b)(1) (2000).

> reasonable is hereby declared to be unlawful.[9]

Thus, the FPA confers upon the Commission the responsibility for ensuring that transmission and wholesale power sales rates and charges, including any rule, regulation, practice or contract affecting them, are just and reasonable and not unduly discriminatory.

7. In *Mississippi Industries v. FERC*,[10] the court recognized the connection between the allocation of capacity and wholesale rates. In that proceeding, the Commission had altered the allocation of capacity and costs of a nuclear generation plant among operating companies of an integrated utility system. Petitioners asserted that, in allocating the cost and capacity of the nuclear plant, the Commission had asserted jurisdiction over generating facilities in direct violation of the FPA section 201(b) prohibition against Commission regulation of generating facilities. Petitioners asserted that "reallocating generation costs falls outside of FERC's rate making jurisdiction and instead falls solely within state

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[9] 16 U.S.C. § 824d(a) (2000). FPA section 206 gives the Commission the ability to review "any rate, charges, or classification" charged by a public utility for any transmission or sale subject to the jurisdiction of the Commission, as well as "any rule, regulation, practice, or contract affecting such rate, charge, or classification. . . ." 16 U.S.C. § 824e(a) (2000).

[10] 808 F.2d 1525 (D.C. Cir.), *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1987) (*Mississippi Industries*).

authority over generation."[11] The court rejected the claim that this action was beyond the Commission's FPA jurisdiction. Instead, it found that the Commission has authority over the allocation of capacity among market participants because this allocation affects wholesale rates. The court stated, "[c]apacity costs are a large component of wholesale rates" and therefore the share of the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy.[12] While the allocation of capacity did not set sales prices, it directly affects costs and "consequently, wholesale rates"[13] and therefore "FERC's jurisdiction under such circumstances is unquestionable."[14] The court further noted that:

> Petitioners ignore the critical point here that, while these provisions [allocating capacity] do not fix wholesale rates, their terms do directly and significantly *affect* the wholesale rates at which the operating companies exchange energy, due to the highly integrated nature of the . . . system.[15]

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[11] *Id.* at 1543.

[12] *Id.* at 1541.

[13] *Id.*

[14] *Id.* (*citing Nantahala Power & Light Co.*, 426 U.S. 953 (1986)).

[15] *Id.* at 1542.

8. Similarly, in *Municipalities of Groton v. FERC*,[16] the court upheld the Commission's authority to review section 9.4(d) of the New England Power Pool Agreement which included a capacity deficiency charge for each participant in the agreement whose prescribed level of generating capacity, known as "capability responsibility," fell by more than one percent below the set level. The court found that these capacity deficiency charges were within the Commission's jurisdiction because they were under "the Commission's inclusive jurisdictional mandate – which reaches discriminatory practices 'with respect to' jurisdictional transmissions, or 'affecting' such transmissions or services. . . ."[17] The court further stated:

> [i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge. This is well within the Commission's authority as delineated in other court opinions.[18]

9. As noted above the Commission likewise has recently addressed this question as it involves resource adequacy in New England. Specifically, in

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[16] 587 F.2d 1296, 1300 (D.C. Cir. 1978) (*Groton*).

[17] *Id.* at 1302.

[18] *Id.* (*citing, e.g., FPC v. Conway Corp.*, 426 U.S. 271 (1976)).

two proceedings involving ISO-NE ICR filings,[19] the CT DPUC argued that, while the Commission has the authority to establish the price of capacity and how capacity requirements will be allocated among LSEs, it does not have the jurisdiction to dictate the amount of ICRs that must be purchased.

10. We find here, as we did in our order addressing ISO-NE's revisions to its methodology for determining ICR,[20] that the ICR is one of the principal determinants of the price of capacity and, therefore, falls within the Commission's jurisdiction to review "any rate, charge or classification" charged by a public utility for electric transmission or sales subject to Commission jurisdiction, and "any rule, regulation, practice, or contract affecting such rate, charge or classification."[21] ISO-NE's mechanism to determine ICRs is a "practice . . . affecting" the price of capacity, and as such falls within the Commission's jurisdiction.

11. As ISO-NE's ICRs have a significant and direct effect on jurisdictional rates and services, they therefore fall within the Commission's jurisdiction. This finding is fully consistent with *Mississippi Industries* and *Groton*. In *Mississippi Industries*, the Commission exercised jurisdiction over the allocation

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[19] *See supra* notes 4, 6.

[20] *ISO New England, Inc.*, 118 FERC ¶ 61,157 at P 15, 19-20, *reh'g denied*, 120 FERC ¶ 61,234 at P 25-30 (2007).

[21] 16 U.S.C. § 824e(a) (2000).

of the capacity of a nuclear generating plant, despite the fact that the FPA does not give the Commission jurisdiction over generating facilities (and indeed reserves that jurisdiction to the states).[22] The court affirmed Commission jurisdiction because of the nexus between the allocation of capacity and the justness and reasonableness of jurisdictional rates under the Entergy System Agreement. The court in *Groton* undertook a similar analysis in upholding Commission jurisdiction in that case. In *Groton*, the Commission had asserted jurisdiction over a charge related to resource adequacy requirements in New England. The court upheld the Commission's order, finding that that the capacity deficiency charge affected jurisdictional rates and that jurisdiction therefore attached "irrespective of the objective underlying that charge."[23]

12. We also note that, in *California Independent System Operator Corporation*,[24] the Commission addressed how the minimum resource adequacy requirements set forth in the Market Redesign and Technology Upgrade (MRTU) Tariff have an effect on jurisdictional rates and services. The Commission explained that:

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[22] *Mississippi Industries*, 808 F.2d at 1543-44.

[23] *Groton*, 587 F.2d at 1302.

[24] 116 FERC ¶ 61,274, at P 1113 (2006) (CAISO Order), *order on reh'g*, 119 FERC ¶ 61,076 (2007) (CAISO Rehearing Order).

> where an interconnected transmission system is operated on [a] regional basis as part of an organized market for electricity, as in California, all users of the system are interdependent, particularly with respect to reliability, *i.e.*, one participant's reliability decisions can impact the reliability of service available to other participants and the related costs the other participants must bear. . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and costs impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory.[25]

13. More recently, in the CAISO Rehearing Order, we reaffirmed our finding on jurisdiction.[26] We found that the adequacy of resources can have a significant effect on jurisdictional rates and services and, therefore, is subject to Commission jurisdiction. We again found that the FPA confers upon the Commission the responsibility for ensuring that jurisdictional rates and charges – including any rule, regulation, practice or contract affecting them – are

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[25] CAISO Order at P 1113.

[26] *See* CAISO Rehearing Order, 119 FERC ¶ 61,076, at P 521-64; *accord, New York State Reliability Council*, 118 FERC ¶ 61,179, at P 31 (2007), *order on reh'g*, 122 FERC ¶ 61,153 (2008).

just and reasonable and not unduly discriminatory or preferential.[27]

14. The Commission acknowledges that FPA section 201 puts limits on the Commission's jurisdiction as it relates to electrical generating capacity. In approving the ICR filing, however, the Commission is not exercising authority over electrical generating capacity or setting the amount of generating capacity that states must build (or require to be built). Rather the Commission is reviewing the means by which ISO-NE determines the amount of resources member load serving entities (LSEs) must provide (which leads ultimately to a determination of the amount of resources each state's LSEs must provide), which as described above directly affects the charges to customers.

15. It is also critical to distinguish between ISO-NE's "capacity" requirement and "electrical generating capacity." In essence, "capacity" (the ability to

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[27] *Id.*; 16 U.S.C. §§ 824d, 824e (2000). We agree, however, that as a general matter a state or region may determine in the first instance the appropriate level of planning reserves by balancing reliability and cost considerations. Thus, in the CAISO Order, we noted that "it is our responsibility to ensure that a workable resource adequacy requirement exists in a market such as that operated by the CAISO. This does not mean that we must determine all the elements of such a program in the first instance. Rather, we can, in appropriate circumstances, defer to state and Local Regulatory Authorities to set those requirements. CAISO Rehearing Order, 119 FERC ¶ 61,076 at P 558 (*citing* CAISO Order, 116 FERC ¶ 61,274 at P 1117).

provide electric energy to serve load, when called by ISO-NE) is the product, and electrical generating capacity is one means, but not the only means, of producing that product. For example, assume that within a particular state, ISO-NE determines that an LSE must provide 100 MW of capacity (in addition to the capacity that the LSE currently has). This does not mean that the LSE must necessarily construct, and the state must permit the construction of, 100 MW of new electrical generating capacity. The LSE could fulfill its capacity obligation to ISO-NE by constructing new electrical generating capacity but it could also add 50 MW of demand response[28] and 50 MW of capacity contracts (from inside or outside the state), or any mix of the above. If a state wishes to place controls on the amount or type of electrical generating capacity built within that state, or at particular locations within that state, the Commission's regulation of ISO-NE's calculation of ICR does not prevent it from doing so.[29] The capacity

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[28] Demand response reduces load to be served, so that less electrical generating capacity is needed to serve load.

[29] *See, e.g., Jersey Central Power & Light Company* v. *Atlantic City Electric Co.*, 111 FERC ¶ 61,179 at P 10, 24-25, 27, *order on reh'g*, 113 FERC ¶ 61,237 at P 6-7, 47-48, 54-58 (2005), *reh'g denied*, 116 FERC ¶ 61,256 at P 13-15 (2006) (complainant sought relief from Commission-jurisdictional contract obligation to build facilities on the basis that, among other reasons, environmental regulation by the State of New Jersey prevented it from fulfilling its contract obligation; Commission responded that contract already contemplated that facilities might not be

(Continued on following page)

requirement that ISO-NE places on an individual LSE may be a factor in a state's ultimate determination as to how much electrical generating capacity is built, and where and by whom. These are not, however, the same determinations, and it is inaccurate to conflate the two.

16. While currently the majority of the New England states' capacity needs are met through electrical generating capacity, this does not mean that that will remain the case in the future. Nothing in the ICR requirement prevents a state from requiring its LSEs to meet capacity requirements through demand response, or through contracts to purchase power (from resources located inside or outside the state), or through more environmentally-friendly generation, or, generally speaking, through resources that meet state health or environmental or land-use planning goals. In essence, ISO-NE says to its LSEs, "Provide X amount of resources." But *how* those resources are provided is up to the LSEs and the states.

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built and already provided complainant with options such as construction of other facilities).

17. Therefore, we find that the Commission has jurisdiction to consider and accept ISO-NE's 2005/2006 Power Year ICR.

By the Commission.

(SEAL)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

APPENDIX H

123 FERC ¶ 61,036
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and
Jon Wellinghoff.

ISO New England, Inc. Docket No. ER05-715-003

ORDER DENYING REHEARING

(Issued April 17, 2008)

1. In this order, the Commission denies rehearing of its February 21, 2008 Order[1] in which it explained the basis for the Commission's jurisdiction over the filing at issue in this proceeding – ISO New England, Inc.'s (ISO-NE) Power Year 2005/2006 Installed Capacity Requirements (ICR) for the New England Control Area.

Background

2. For over 20 years, ISO-NE has imposed ICRs on its members in order to maintain adequate system reliability.[2] The ICR is a projection of the minimum

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[1] *ISO New England, Inc.*, 122 FERC ¶ 61,144 (2008).

[2] Prior to the existence of the ISO-NE the requirements were imposed on the members of the New England Power Pool

(Continued on following page)

amount of capacity required to serve load reliably in the New England region. The ICR is used to determine the monthly unforced capacity (UCAP) requirements (with various adjustments) that each market participant must purchase. ISO-NE calculates the ICR to meet system design criteria with a Loss of Load Expectation of one day in ten years. To meet their UCAP obligations, market participants must self-supply, purchase UCAP through bilateral transactions, or obtain capacity credits from tie-line benefits, or they must make up any deficiencies in the ISO-NE administered installed capacity market. The ICR directly affects the determination of the clearing price in the capacity market and so affects the charges to customers. If a market participant does not have or acquire sufficient capacity, it must pay a deficiency rate.

3. On March 21, 2005, as supplemented on April 1, 2005, ISO-NE filed its ICR for the 2005/2006 Power Year. The Connecticut Department of Public Utility Control (CT DPUC) protested the substance of the ICR and also argued that the Commission does not have jurisdiction to regulate resource adequacy, a matter the CT DPUC argued that the Federal Power Act (FPA) leaves to the states. The Commission accepted ISO-NE's 2005/2006 Power Year ICR with

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(NEPOOL), and the ICR was then called NEPOOL's Objective Capability (OC).

modifications.[3] On appeal, the U.S. Court of Appeals for the District of Columbia Circuit, without addressing the merits, remanded the issue of jurisdiction to the Commission for an explanation of the basis for the Commission's jurisdiction.[4] In the February 21 Order, the Commission explained the basis of its jurisdiction.

4. On February 28, 2008, the CT DPUC sought rehearing of the Commission's February 21, 2008 Order. The CT DPUC's request for rehearing is for the most part identical to the request for rehearing it filed in Docket No. ER07-655-001, the ISO-NE 2007/2008 Power Year ICR proceeding. The CT DPUC has raised the same argument, that the Commission lacks jurisdiction over ICR, in response to two other ISO-NE filings. The first of those proceedings involved ISO-NE's filing a tariff change in Docket No. ER07-365 to revise the processes and methodologies used to determine ICR. In response to that filing the Commission accepted the tariff changes and explained the basis of its jurisdiction.[5] The CT DPUC has appealed that decision.[6] The second of those

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[3] *ISO New England, Inc.*, 111 FERC ¶ 61,185, *reh'g denied*, 112 FERC ¶ 61,254 (2005).

[4] *Connecticut Department of Public Utility Control v. FERC*, 484 F.3d 558 (D.C. Cir. 2007).

[5] *ISO New England, Inc.*, 118 FERC ¶ 61,157, *reh'g denied*, 120 FERC ¶ 61,234 (2007).

[6] *Connecticut Department of Public Utility Control v. FERC*, No. 07-1375 (D.C. Cir. filed September 19, 2007).

proceedings involved ISO-NE's just-noted filing in Docket No. ER07-655 of its 2007/2008 Power Year ICR. The Commission accepted the ISO-NE's 2007/2008 Power Year ICR, and again explained the basis of its jurisdiction.[7] The CT DPUC has also appealed that decision.[8]

5. On March 20, 2008, Richard Blumenthal, Attorney General for the State of Connecticut (CT AG) also filed for rehearing of the February 21, 2008 Order. The CT AG states that it adopts and supports the CT DPUC's request for rehearing.

6. On March 14, 2008, ISO-NE filed a motion for leave to answer and an answer to the CT DPUC's request for rehearing. ISO-NE asks the Commission to deny rehearing. On March 17, 2008, the New England Power Pool Participants Committee filed a motion for leave to answer and an answer to the CT DPUC's request for rehearing. The New England Power Pool Participants Committee urges the Commission to deny rehearing.

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[7] *ISO New England, Inc.*, 119 FERC ¶ 61,161, *reh'g denied*, 121 FERC ¶ 61,125 (2007).

[8] *Connecticut Department of Public Utility Control v. FERC*, No. 07-1460 (D.C. Cir. filed November 13, 2007).

Discussion

Procedural Matters

7. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2007), provides that the Commission will not permit answers to requests for rehearing. We will accordingly reject the answers filed by ISO-NE and the New England Power Pool Participants Committee.

Denial of Rehearing

8. As noted above, CT DPUC's request for rehearing of the February 21, 2008 Order, which the CT AG adopts, is virtually a verbatim repetition of its request for rehearing filed in Docket No. ER07-655-001, the ISO-NE 2007/2008 Power Year ICR proceeding.[9] We accordingly will deny rehearing in this proceeding for the same reasons rehearing was denied in Docket No. ER07-655-001.[10]

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[9] The ICR values established in this proceeding, which addresses the 2005/2006 Power Year ICR, pre-date the implementation of New England's Forward Capacity Market (FCM); the FCM is relevant to the 2007/2008 Power Year ICR proceeding, but not relevant to the instant proceeding, the 2005/2006 Power Year ICR proceeding. Thus, insofar as CT DPUC's request for rehearing in this proceeding makes arguments referencing FCM, they are not relevant to this proceeding.

[10] *ISO New England Inc.*, 121 FERC ¶ 61,125 (2007).

The Commission orders:

(A) ISO-NE's and the New England Power Pool Participants Committee's answers to the CT DPUC's request for rehearing are hereby rejected.

(B) CT DPUC's and CT AG's requests for rehearing are hereby denied.

By the Commission.

(SEAL)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

APPENDIX I

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 07-1375 **September Term 2008**

FERC-120-61234

Filed On: July 28, 2009

Connecticut Department
of Public Utility Control,

Petitioner

v.

Federal Energy Regulatory
Commission,

Respondent

New England Power Pool
Participants Committee, et al.,

Intervenors

Consolidated with 07-1460, 08-1175

BEFORE: Tatel, Garland, and Griffith, Circuit Judges

ORDER

Upon consideration of petitioner's petition for panel rehearing filed on July 14, 2009, it is

ORDERED that the petition be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY:
/s/ Michael C. McGrail
Deputy Clerk

APPENDIX J

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 07-1375 **September Term 2008**

FERC-120-61234

Filed On: July 28, 2009

Connecticut Department
of Public Utility Control,

Petitioner

v.

Federal Energy Regulatory
Commission,

Respondent

New England Power Pool
Participants Committee, et al.,

Intervenors

Consolidated with 07-1460, 08-1175

BEFORE: Sentelle, Chief Judge, and Ginsburg,* Henderson,* Rogers, Tatel, Garland, Brown, Griffith, and Kavanaugh, Circuit Judges

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* Circuit Judges Ginsburg and Henderson did not participate in this matter.

ORDER

Upon consideration of petitioner's petition for rehearing en banc, and the absence of a request by any member of the court for a vote, it is

ORDERED that the petition be denied.

Per Curiam

FOR THE COURT:
Mark J. Langer, Clerk

BY:
/s/ Michael C. McGrail
Deputy Clerk

APPENDIX K

RELEVANT STATUTORY PROVISIONS

The Federal Power Act, tit. II, ch. 687, 49 Stat. 803, 838-63 (1935) (codified, as amended, at 16 U.S.C. §§ 824-824w and 825-825u) (2006) provides, in relevant parts:

§ 824. Declaration of policy; application of subchapter

(a) Federal regulation of transmission and sale of electric energy

It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

(b) Use or sale of electric energy in interstate commerce

(1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission

of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this subchapter and subchapter III of this chapter, over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

(2) Notwithstanding subsection (f) of this section, the provisions of sections 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824*o*, 824p, 824q, 824r, 824s, 824t, 824u, and 824v shall apply to the entities described in such provisions, and such entities shall be subject to the jurisdiction of the Commission for purposes of carrying out such provisions and for purposes of applying the enforcement authorities of this chapter with respect to such provisions. Compliance with any order or rule of the Commission under the provisions of section 824b(a)(2), 824e(e), 824i, 824j, 824j-1, 824k, 824*o*, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title, shall not make an electric utility or other entity subject to the jurisdiction of the Commission for any purposes other than the purposes specified in the preceding sentence.

(c) Electric energy in interstate commerce

For the purpose of this subchapter, electric energy shall be held to be transmitted in interstate

commerce if transmitted from a State and consumed at any point outside thereof; but only insofar as such transmission takes place within the United States.

(d) "Sale of electric energy at wholesale" defined

The term "sale of electric energy at wholesale" when used in this subchapter, means a sale of electric energy to any person for resale.

(e) "Public utility" defined

The term "public utility" when used in this subchapter and subchapter III of this chapter means any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter (other than facilities subject to such jurisdiction solely by reason of section 824e(e), 824e(f)[1], 824i, 824j, 824j-1, 824k, 824*o*, 824p, 824q, 824r, 824s, 824t, 824u, or 824v of this title).

(f) United States, State, political subdivision of a State, or agency or instrumentality thereof exempt

No provision in this subchapter shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural

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[1] So in original, Section 824e of this title does not contain a subsec. (f).

Electrification Act of 1936 (7 U.S.C. 901 et seq.) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto.

(g) Books and records

(1) Upon written order of a State commission, a State commission may examine the books, accounts, memoranda, contracts, and records of –

(A) an electric utility company subject to its regulatory authority under State law,

(B) any exempt wholesale generator selling energy at wholesale to such electric utility, and

(C) any electric utility company, or holding company thereof, which is an associate company or affiliate of an exempt wholesale generator which sells electric energy to an electric utility company referred to in subparagraph (A),

wherever located, if such examination is required for the effective discharge of the State commission's regulatory responsibilities affecting the provision of electric service.

(2) Where a State commission issues an order pursuant to paragraph (1), the State commission

shall not publicly disclose trade secrets or sensitive commercial information.

(3) Any United States district court located in the State in which the State commission referred to in paragraph (1) is located shall have jurisdiction to enforce compliance with this subsection.

(4) Nothing in this section shall –

(A) preempt applicable State law concerning the provision of records and other information; or

(B) in any way limit rights to obtain records and other information under Federal law, contracts, or otherwise.

(5) As used in this subsection the terms "affiliate", "associate company", "electric utility company", "holding company", "subsidiary company", and "exempt wholesale generator" shall have the same meaning as when used in the Public Utility Holding Company Act of 2005 [42 U.S.C. § 16451 et seq.].

§ 824a. Interconnection and coordination of facilities; emergencies; transmission to foreign countries

(a) Regional districts; establishment; notice to State commissions

For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural

resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnection and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations, and shall receive and consider such views and recommendations.

(b) Sale or exchange of energy; establishing physical connections

Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest

it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided*, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.

(c) Temporary connection and exchange of facilities during emergency

During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order

such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

(d) Temporary connection during emergency by persons without jurisdiction of Commission

During the continuance of any emergency requiring immediate action, any person engaged in the transmission or sale of electric energy and not otherwise subject to the jurisdiction of the Commission may make such temporary connections with any public utility subject to the jurisdiction of the Commission or may construct such temporary facilities for the transmission of electric energy in interstate commerce as may be necessary or appropriate to meet such emergency, and shall not become subject to the jurisdiction of the Commission by reason of such temporary connection or temporary construction: *Provided*, That such temporary connection shall be discontinued or such temporary construction removed or otherwise disposed of upon the termination of such

emergency: *Provided further,* That upon approval of the Commission permanent connections for emergency use only may be made hereunder.

(e) Transmission of electric energy to foreign country

After six months from August 26, 1935, no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as the Commission may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.

(f) Transmission or sale at wholesale of electric energy; regulation

The ownership or operation of facilities for the transmission or sale at wholesale of electric energy which is (a) generated within a State and transmitted

from the State across an international boundary and not thereafter transmitted into any other State, or (b) generated in a foreign country and transmitted across an international boundary into a State and not thereafter transmitted into any other State, shall not make a person a public utility subject to regulation as such under other provisions of this subchapter. The State within which any such facilities are located may regulate any such transaction insofar as such State regulation does not conflict with the exercise of the Commission's powers under or relating to subsection (e) of this section.

(g) Continuance of service

In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to –

(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity which would affect such utility's capability of serving its wholesale customers,

(2) submit to the Commission, and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting –

(A) shortages of electric energy or capacity, and

(B) circumstances which may result in such shortages, and

(3) accommodate any such shortages or circumstances in a manner which shall –

(A) give due consideration to the public health, safety, and welfare, and

(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage.

§ 824b. Disposition of property; consolidations; purchase of securities

(a) Authorization

(1) No public utility shall, without first having secured an order of the Commission authorizing it to do so –

(A) sell, lease, or otherwise dispose of the whole of its facilities subject to the jurisdiction of the Commission, or any part thereof of a value in excess of $10,000,000;

(B) merge or consolidate, directly or indirectly, such facilities or any part thereof with those of any other person, by any means whatsoever;

(C) purchase, acquire, or take any security with a value in excess of $10,000,000 of any other public utility; or

(D) purchase, lease, or otherwise acquire an existing generation facility –

(i) that has a value in excess of $10,000,000; and

(ii) that is used for interstate wholesale sales and over which the Commission has jurisdiction for ratemaking purposes.

(2) No holding company in a holding company system that includes a transmitting utility or an electric utility shall purchase, acquire, or take any security with a value in excess of $10,000,000 of, or, by any means whatsoever, directly or indirectly, merge or consolidate with, a transmitting utility, an electric utility company, or a holding company in a holding company system that includes a transmitting utility, or an electric utility company, with a value in excess of $10,000,000 without first having secured an order of the Commission authorizing it to do so.

(3) Upon receipt of an application for such approval the Commission shall give reasonable notice in writing to the Governor and State commission of each of the States in which the physical property affected, or any part thereof, is situated, and to such other persons as it may deem advisable.

(4) After notice and opportunity for hearing, the Commission shall approve the proposed disposition, consolidation, acquisition, or change in control, if it finds that the proposed transaction will be consistent with the public interest, and will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the

Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.

(5) The Commission shall, by rule, adopt procedures for the expeditious consideration of applications for the approval of dispositions, consolidations, or acquisitions, under this section. Such rules shall identify classes of transactions, or specify criteria for transactions, that normally meet the standards established in paragraph (4). The Commission shall provide expedited review for such transactions. The Commission shall grant or deny any other application for approval of a transaction not later than 180 days after the application is filed. If the Commission does not act within 180 days, such application shall be deemed granted unless the Commission finds, based on good cause, that further consideration is required to determine whether the proposed transaction meets the standards of paragraph (4) and issues an order tolling the time for acting on the application for not more than 180 days, at the end of which additional period the Commission shall grant or deny the application.

(6) For purposes of this subsection, the terms "associate company", "holding company", and "holding company system" have the meaning given those terms in the Public Utility Holding Company Act of 2005. [42 U.S.C. 16451 et seq.].

(b) Orders of Commission

The Commission may grant any application for an order under this section in whole or in part and upon such terms and conditions as it finds necessary or appropriate to secure the maintenance of adequate service and the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may from time to time for good cause shown make such orders supplemental to any order made under this section as it may find necessary or appropriate.

* * *

§ 824d. Rates and charges; schedules; suspension of new rates; automatic adjustment clauses

(a) Just and reasonable rates

All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Preference or advantage unlawful

No public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Schedules

Under such rules and regulations as the Commission may prescribe, every public utility shall file with the Commission, within such time and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection schedules showing all rates and charges for any transmission or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Notice required for rate changes

Unless the Commission otherwise orders, no change shall be made by any public utility in any such rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the

public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall take effect and the manner in which they shall be filed and published.

(e) Suspension of new rates; hearings; five-month period

Whenever any such new schedule is filed the Commission shall have authority, either upon complaint or upon its own initiative without complaint, at once, and, if it so orders, without answer or formal pleading by the public utility, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the public utility affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or

service goes into effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of such five months, the proposed change of rate, charge, classification, or service shall go into effect at the end of such period, but in case of a proposed increased rate or charge, the Commission may by order require the interested public utility or public utilities to keep accurate account in detail of all amounts received by reason of such increase, specifying by whom and in whose behalf such amounts are paid, and upon completion of the hearing and decision may by further order require such public utility or public utilities to refund, with interest, to the persons in whose behalf such amounts were paid, such portion of such increased rates or charges as by its decision shall be found not justified. At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

(f) Review of automatic adjustment clauses and public utility practices; action by Commission; "automatic adjustment clause" defined

(1) Not later than 2 years after November 9, 1978, and not less often than every 4 years thereafter, the Commission shall make a thorough review of automatic adjustment clauses in public utility rate schedules to examine –

(A) whether or not each such clause effectively provides incentives for efficient use of resources (including economical purchase and use of fuel and electric energy), and

(B) whether any such clause reflects any costs other than costs which are –

(i) subject to periodic fluctuations and

(ii) not susceptible to precise determinations in rate cases prior to the time such costs are incurred.

Such review may take place in individual rate proceedings or in generic or other separate proceedings applicable to one or more utilities.

(2) Not less frequently than every 2 years, in rate proceedings or in generic or other separate proceedings, the Commission shall review, with respect to each public utility, practices under any automatic adjustment clauses of such utility to insure efficient use of resources (including economical purchase and use of fuel and electric energy) under such clauses.

(3) The Commission may, on its own motion or upon complaint, after an opportunity for an evidentiary hearing, order a public utility to –

(A) modify the terms and provisions of any automatic adjustment clause, or

(B) cease any practice in connection with the clause,

if such clause or practice does not result in the economical purchase and use of fuel, electric energy, or other items, the cost of which is included in any rate schedule under an automatic adjustment clause.

(4) As used in this subsection, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include any rate which takes effect subject to refund and subject to a later determination of the appropriate amount of such rate.

§ 824e. Power of Commission to fix rates and charges; determination of cost of production or transmission

(a) Unjust or preferential rates, etc.; statement of reasons for changes; hearing; specification of issues

Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find

that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated.

(b) Refund effective date; preferential proceedings; statement of reasons for delay; burden of proof; scope of refund order; refund orders in cases of dilatory behavior; interest

Whenever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date of the

filing of such complaint nor later than 5 months after the filing of such complaint. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date of the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the publication date. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under section 824d of this title and otherwise act as speedily as possible. If no final decision is rendered by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion of any proceeding under this section, the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: *Provided,* That if the proceeding is not concluded within fifteen months after the

refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the public utility, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

(c) Refund considerations; shifting costs; reduction in revenues; "electric utility companies" and "registered holding company" defined

Notwithstanding subsection (b) of this section, in a proceeding commenced under this section involving two or more electric utility companies of a registered holding company, refunds which might otherwise be payable under subsection (b) of this section shall not be ordered to the extent that such refunds would result from any portion of a Commission order that (1) requires a decrease in system production or transmission costs to be paid by one or more of such electric companies; and (2) is based upon a determination that the amount of such decrease should be paid through an increase in the costs to be paid by other electric utility companies of such registered holding company: *Provided,* That refunds, in whole or in part, may be ordered by the Commission if it determines that the registered holding company

would not experience any reduction in revenues which results from an inability of an electric utility company of the holding company to recover such increase in costs for the period between the refund effective date and the effective date of the Commission's order. For purposes of this subsection, the terms "electric utility companies" and "registered holding company" shall have the same meanings as provided in the Public Utility Holding Company Act of 1935, as amended.[1]

(d) Investigation of costs

The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or transmission of electric energy by means of facilities under the jurisdiction of the Commission in cases where the Commission has no authority to establish a rate governing the sale of such energy.

(e) Short-term sales

(1) In this subsection:

(A) The term "short-term sale" means an agreement for the sale of electric energy at wholesale in interstate commerce that is for a period of 31 days or less (excluding monthly contracts subject to automatic renewal).

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[1] See References in Text note below.

(B) The term "applicable Commission rule" means a Commission rule applicable to sales at wholesale by public utilities that the Commission determines after notice and comment should also be applicable to entities subject to this subsection.

(2) If an entity described in section 824(f) of this title voluntarily makes a short-term sale of electric energy through an organized market in which the rates for the sale are established by Commission-approved tariff (rather than by contract) and the sale violates the terms of the tariff or applicable Commission rules in effect at the time of the sale, the entity shall be subject to the refund authority of the Commission under this section with respect to the violation.

(3) This section shall not apply to –

(A) any entity that sells in total (including affiliates of the entity) less than 8,000,000 megawatt hours of electricity per year; or

(B) an electric cooperative.

(4)(A) The Commission shall have refund authority under paragraph (2) with respect to a voluntary short term sale of electric energy by the Bonneville Power Administration only if the sale is at an unjust and unreasonable rate.

(B) The Commission may order a refund under subparagraph (A) only for short-term sales made by the Bonneville Power Administration at rates that are higher than the highest just and reasonable rate

charged by any other entity for a short-term sale of electric energy in the same geographic market for the same, or most nearly comparable, period as the sale by the Bonneville Power Administration.

(C) In the case of any Federal power marketing agency or the Tennessee Valley Authority, the Commission shall not assert or exercise any regulatory authority or power under paragraph (2) other than the ordering of refunds to achieve a just and reasonable rate.

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§ 824f. Ordering furnishing of adequate service

Whenever the Commission, upon complaint of a State commission, after notice to each State commission and public utility affected and after opportunity for hearing, shall find that any interstate service of any public utility is inadequate or insufficient, the Commission shall determine the proper, adequate, or sufficient service to be furnished, and shall fix the same by its order, rule, or regulation: *Provided*, That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel the public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers.

* * *

§ 824*o*. Electric reliability

(a) Definitions

For purposes of this section:

(1) The term "bulk-power system" means –

(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

(B) electric energy from generation facilities needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy.

(2) The terms "Electric Reliability Organization" and "ERO" mean the organization certified by the Commission under subsection (c) of this section the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

(3) The term "reliability standard" means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

(4) The term "reliable operation" means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

(5) The term "Interconnection" means a geographic area in which the operation of bulk-power system components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain reliable operation of the facilities within their control.

(6) The term "transmission organization" means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.

(7) The term "regional entity" means an entity having enforcement authority pursuant to subsection (e)(4) of this section.

(8) The term "cybersecurity incident" means a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the bulk power system.

(b) Jurisdiction and applicability

(1) The Commission shall have jurisdiction, within the United States, over the ERO certified by the Commission under subsection (c) of this section, any regional entities, and all users, owners and operators of the bulk-power system, including but not limited to the entities described in section 824(f) of this title, for purposes of approving reliability standards established under this section and enforcing compliance with this section. All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.

(2) The Commission shall issue a final rule to implement the requirements of this section not later than 180 days after August 8, 2005.

(c) Certification

Following the issuance of a Commission rule under subsection (b)(2) of this section, any person may submit an application to the Commission for

certification as the Electric Reliability Organization. The Commission may certify one such ERO if the Commission determines that such ERO –

(1) has the ability to develop and enforce, subject to subsection (e)(2) of this section, reliability standards that provide for an adequate level of reliability of the bulk-power system; and

(2) has established rules that –

(A) assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decisionmaking in any ERO committee or subordinate organizational structure;

(B) allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section;

(C) provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties in accordance with subsection (e) of this section (including limitations on activities, functions, or operations, or other appropriate sanctions);

(D) provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties; and

(E) provide for taking, after certification, appropriate steps to gain recognition in Canada and Mexico.

(d) Reliability standards

(1) The Electric Reliability Organization shall file each reliability standard or modification to a reliability standard that it proposes to be made effective under this section with the Commission.

(2) The Commission may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a reliability standard and to the technical expertise of a regional entity organized on an Interconnection-wide basis with respect to a reliability standard to be applicable within that Interconnection, but shall not defer with respect to the effect of a standard on competition. A proposed standard or modification shall take effect upon approval by the Commission.

(3) The Electric Reliability Organization shall rebuttably presume that a proposal from a regional entity organized on an Interconnection-wide basis for a reliability standard or modification to a reliability standard to be applicable on an Interconnection-wide

basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

(4) The Commission shall remand to the Electric Reliability Organization for further consideration a proposed reliability standard or a modification to a reliability standard that the Commission disapproves in whole or in part.

(5) The Commission, upon its own motion or upon complaint, may order the Electric Reliability Organization to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section.

(6) The final rule adopted under subsection (b)(2) of this section shall include fair processes for the identification and timely resolution of any conflict between a reliability standard and any function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission applicable to a transmission organization. Such transmission organization shall continue to comply with such function, rule, order, tariff, rate schedule or agreement accepted, approved, or ordered by the Commission until –

(A) the Commission finds a conflict exists between a reliability standard and any such provision;

(B) the Commission orders a change to such provision pursuant to section 824e of this title; and

(C) the ordered change becomes effective under this subchapter.

If the Commission determines that a reliability standard needs to be changed as a result of such a conflict, it shall order the ERO to develop and file with the Commission a modified reliability standard under paragraph (4) or (5) of this subsection.

(e) Enforcement

(1) The ERO may impose, subject to paragraph (2), a penalty on a user or owner or operator of the bulk-power system for a violation of a reliability standard approved by the Commission under subsection (d) of this section if the ERO, after notice and an opportunity for a hearing –

(A) finds that the user or owner or operator has violated a reliability standard approved by the Commission under subsection (d) of this section; and

(B) files notice and the record of the proceeding with the Commission.

(2) A penalty imposed under paragraph (1) may take effect not earlier than the 31st day after the ERO files with the Commission notice of the penalty and the record of proceedings. Such penalty shall be subject to review by the Commission, on its own

motion or upon application by the user, owner or operator that is the subject of the penalty filed within 30 days after the date such notice is filed with the Commission. Application to the Commission for review, or the initiation of review by the Commission on its own motion, shall not operate as a stay of such penalty unless the Commission otherwise orders upon its own motion or upon application by the user, owner or operator that is the subject of such penalty. In any proceeding to review a penalty imposed under paragraph (1), the Commission, after notice and opportunity for hearing (which hearing may consist solely of the record before the ERO and opportunity for the presentation of supporting reasons to affirm, modify, or set aside the penalty), shall by order affirm, set aside, reinstate, or modify the penalty, and, if appropriate, remand to the ERO for further proceedings. The Commission shall implement expedited procedures for such hearings.

(3) On its own motion or upon complaint, the Commission may order compliance with a reliability standard and may impose a penalty against a user or owner or operator of the bulk-power system if the Commission finds, after notice and opportunity for a hearing, that the user or owner or operator of the bulk-power system has engaged or is about to engage in any acts or practices that constitute or will constitute a violation of a reliability standard.

(4) The Commission shall issue regulations authorizing the ERO to enter into an agreement to delegate authority to a regional entity for the purpose

of proposing reliability standards to the ERO and enforcing reliability standards under paragraph (1) if –

(A) the regional entity is governed by –

(i) an independent board;

(ii) a balanced stakeholder board; or

(iii) a combination independent and balanced stakeholder board.

(B) the regional entity otherwise satisfies the provisions of subsection (c)(1) and (2) of this section; and

(C) the agreement promotes effective and efficient administration of bulk-power system reliability.

The Commission may modify such delegation. The ERO and the Commission shall rebuttably presume that a proposal for delegation to a regional entity organized on an Interconnection-wide basis promotes effective and efficient administration of bulk-power system reliability and should be approved. Such regulation may provide that the Commission may assign the ERO's authority to enforce reliability standards under paragraph (1) directly to a regional entity consistent with the requirements of this paragraph.

(5) The Commission may take such action as is necessary or appropriate against the ERO or a regional entity to ensure compliance with a reliability

standard or any Commission order affecting the ERO or a regional entity.

(6) Any penalty imposed under this section shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of such user, owner, or operator to remedy the violation in a timely manner.

(f) Changes in Electric Reliability Organization rules

The Electric Reliability Organization shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose. The Commission, upon its own motion or complaint, may propose a change to the rules of the ERO. A proposed rule or proposed rule change shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c) of this section.

(g) Reliability reports

The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.

(h) Coordination with Canada and Mexico

The President is urged to negotiate international agreements with the governments of Canada and Mexico to provide for effective compliance with reliability standards and the effectiveness of the ERO in the United States and Canada or Mexico.

(i) Savings provisions

(1) The ERO shall have authority to develop and enforce compliance with reliability standards for only the bulk-power system.

(2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.

(3) Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, except that the State of New York may establish rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the reliability standards.

(4) Within 90 days of the application of the Electric Reliability Organization or other affected party, and after notice and opportunity for comment, the Commission shall issue a final order determining whether a State action is inconsistent with a reliability standard, taking into consideration any recommendation of the ERO.

(5) The Commission, after consultation with the ERO and the State taking action, may stay the effectiveness of any State action, pending the Commission's issuance of a final order.

(j) Regional advisory bodies

The Commission shall establish a regional advisory body on the petition of at least two-thirds of the States within a region that have more than one-half of their electric load served within the region. A regional advisory body shall be composed of one member from each participating State in the region, appointed by the Governor of each State, and may include representatives of agencies, States, and provinces outside the United States. A regional advisory body may provide advice to the Electric Reliability Organization, a regional entity, or the Commission regarding the governance of an existing or proposed regional entity within the same region, whether a standard proposed to apply within the region is just, reasonable, not unduly discriminatory or preferential, and in the public interest, whether fees proposed to be assessed within the region are

just, reasonable, not unduly discriminatory or preferential, and in the public interest and any other responsibilities requested by the Commission. The Commission may give deference to the advice of any such regional advisory body if that body is organized on an Interconnection-wide basis.

(k) Alaska and Hawaii

The provisions of this section do not apply to Alaska or Hawaii.

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§ 825. Accounts and records

(a) Duty to keep

Every licensee and public utility shall make, keep, and preserve for such periods, such accounts, records of cost-accounting procedures, correspondence, memoranda, papers, books, and other records as the Commission may by rules and regulations prescribe as necessary or appropriate for purposes of the administration of this chapter, including accounts, records, and memoranda of the generation, transmission, distribution, delivery, or sale of electric energy, the furnishing of services or facilities in connection therewith, and receipts and expenditures with respect to any of the foregoing: *Provided, however,* That nothing in this chapter shall relieve any public utility from keeping any accounts, memoranda, or records which such public utility may be required to keep by or under authority of the laws of any State.

The Commission may prescribe a system of accounts to be kept by licensees and public utilities and may classify such licensees and public utilities and prescribe a system of accounts for each class. The Commission, after notice and opportunity for hearing, may determine by order the accounts in which particular outlays and receipts shall be entered, charged, or credited. The burden of proof to justify every accounting entry questioned by the Commission shall be on the person making, authorizing, or requiring such entry, and the Commission may suspend a charge or credit pending submission of satisfactory proof in support thereof.

(b) Access to and examination by the Commission

The Commission shall at all times have access to and the right to inspect and examine all accounts, records, and memoranda of licensees and public utilities, and it shall be the duty of such licensees and public utilities to furnish to the Commission, within such reasonable time as the Commission may order, any information with respect thereto which the Commission may by order require, including copies of maps, contracts, reports of engineers, and other data, records, and papers, and to grant to all agents of the Commission free access to its property and its accounts, records, and memoranda when requested so to do. No member, officer, or employee of the Commission shall divulge any fact or information

which may come to his knowledge during the course of examination of books or other accounts, as hereinbefore provided, except insofar as he may be directed by the Commission or by a court.

(c) Controlling individual

The books, accounts, memoranda, and records of any person who controls, directly or indirectly, a licensee or public utility subject to the jurisdiction of the Commission, and of any other company controlled by such person, insofar as they relate to transactions with or the business of such licensee or public utility, shall be subject to examination on the order of the Commission.

* * *

§ 825b. Requirements applicable to agencies of United States

All agencies of the United States engaged in the generation and sale of electric energy for ultimate distribution to the public shall be subject, as to all facilities used for such generation and sale, and as to the electric energy sold by such agency, to the provisions of sections 825 and 825a of this title, so far as may be practicable, and shall comply with the provisions of such sections and with the rules and regulations of the Commission thereunder to the same extent as may be required in the case of a public utility.

* * *

§ 825*l*. Review of orders

(a) Application for rehearing; time periods; modification of order

Any person, electric utility, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this chapter to which such person, electric utility, State, municipality, or State commission is a party may apply for a rehearing within thirty days after the issuance of such order. The application for rehearing shall set forth specifically the ground or grounds upon which such application is based. Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing. Unless the Commission acts upon the application for rehearing within thirty days after it is filed, such application may be deemed to have been denied. No proceeding to review any order of the Commission shall be brought by any entity unless such entity shall have made application to the Commission for a rehearing thereon. Until the record in a proceeding shall have been filed in a court of appeals, as provided in subsection (b) of this section, the Commission may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.

(b) Judicial review

Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States Court of Appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part. A copy of such petition shall forthwith be transmitted by the clerk of the court to any member of the Commission and thereupon the Commission shall file with the court the record upon which the order complained of was entered, as provided in section 2112 of Title 28. Upon the filing of such petition such court shall have jurisdiction, which upon the filing of the record with it shall be exclusive, to affirm, modify, or set aside such order in whole or in part. No objection to the order of the Commission shall be considered by the court unless such objection shall have been urged before the Commission in the application for rehearing unless there is reasonable ground for failure so to do. The finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive. If any party shall apply to the court for leave to adduce additional evidence, and shall show to the satisfaction of the court that such additional

evidence is material and that there were reasonable grounds for failure to adduce such evidence in the proceedings before the Commission, the court may order such additional evidence to be taken before the Commission and to be adduced upon the hearing in such manner and upon such terms and conditions as to the court may seem proper. The Commission may modify its findings as to the facts by reason of the additional evidence so taken, and it shall file with the court such modified or new findings which, if supported by substantial evidence, shall be conclusive, and its recommendation, if any, for the modification or setting aside of the original order. The judgment and decree of the court, affirming, modifying, or setting aside, in whole or in part, any such order of the Commission, shall be final, subject to review by the Supreme Court of the United States upon certiorari or certification as provided in section 1254 of title 28.

(c) Stay of Commission's order

The filing of an application for rehearing under subsection (a) of this section shall not, unless specifically ordered by the Commission, operate as a stay of the Commission's order. The commencement of proceedings under subsection (b) of this section shall not, unless specifically ordered by the court, operate as a stay of the Commission's order.

ENERGY POLICY ACT OF 2005

Pub. L. 109-58, 119 Stat. 594
109th Congress

An Act

To ensure jobs for our future with secure, affordable, and reliable energy.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

TITLE XII – ELECTRICITY

Subtitle A – Reliability Standards

SEC. 1211. ELECTRIC RELIABILITY STANDARDS.

(a) IN GENERAL. – Part II of the Federal Power Act (16 U.S.C. 824 et seq.) is amended by adding at the end the following:

"SEC. 215. ELECTRIC RELIABILITY.

"(a) DEFINITIONS. – For purposes of this section:

"(1) The term 'bulk-power system' means –

"(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and

"(B) electric energy from generation facilities needed to maintain transmission system reliability.

The term does not include facilities used in the local distribution of electric energy.

"(2) The terms 'Electric Reliability Organization' and 'ERO' mean the organization certified by the Commission under subsection (c) the purpose of which is to establish and enforce reliability standards for the bulk-power system, subject to Commission review.

"(3) The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.

"(4) The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.

"(5) The term 'Interconnection' means a geographic area in which the operation of bulk-power system components is synchronized such that the failure of one or more of such components may adversely affect the ability of the

operators of other components within the system to maintain reliable operation of the facilities within their control.

"(6) The term 'transmission organization' means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.

"(7) The term 'regional entity' means an entity having enforcement authority pursuant to subsection (e)(4).

"(8) The term 'cybersecurity incident' means a malicious act or suspicious event that disrupts, or was an attempt to disrupt, the operation of those programmable electronic devices and communication networks including hardware, software and data that are essential to the reliable operation of the bulk power system.

"(b) JURISDICTION AND APPLICABILITY. – (1) The Commission shall have jurisdiction, within the United States, over the ERO certified by the Commission under subsection (c), any regional entities, and all users, owners and operators of the bulk-power system, including but not limited to the entities described in section 201(f), for purposes of approving reliability standards established under this section and enforcing compliance with this section. All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.

"(2) The Commission shall issue a final rule to implement the requirements of this section not later than 180 days after the date of enactment of this section.

"(c) CERTIFICATION. – Following the issuance of a Commission rule under subsection (b)(2), any person may submit an application to the Commission for certification as the Electric Reliability Organization. The Commission may certify one such ERO if the Commission determines that such ERO –

"(1) has the ability to develop and enforce, subject to subsection (e)(2), reliability standards that provide for an adequate level of reliability of the bulk-power system; and

"(2) has established rules that –

"(A) assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decisionmaking in any ERO committee or subordinate organizational structure;

"(B) allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section;

"(C) provide fair and impartial procedures for enforcement of reliability standards through the imposition of penalties in accordance with subsection (e) (including limitations on activities, functions, or operations, or other appropriate sanctions);

"(D) provide for reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing reliability standards and otherwise exercising its duties; and

"(E) provide for taking, after certification, appropriate steps to gain recognition in Canada and Mexico.

"(d) RELIABILITY STANDARDS. – (1) The Electric Reliability Organization shall file each reliability standard or modification to a reliability standard that it proposes to be made effective under this section with the Commission.

"(2) The Commission may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a reliability standard and to the technical expertise of a regional entity organized on an Interconnection-wide basis with respect to a reliability standard to be applicable within that Interconnection, but shall not defer with respect to the effect of a standard on competition. A proposed standard or modification shall take effect upon approval by the Commission.

"(3) The Electric Reliability Organization shall rebuttably presume that a proposal from a regional entity organized on an Interconnection-wide basis for a reliability standard or modification to a reliability

standard to be applicable on an Interconnection-wide basis is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

"(4) The Commission shall remand to the Electric Reliability Organization for further consideration a proposed reliability standard or a modification to a reliability standard that the Commission disapproves in whole or in part.

"(5) The Commission, upon its own motion or upon complaint, may order the Electric Reliability Organization to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section.

"(6) The final rule adopted under subsection (b)(2) shall include fair processes for the identification and timely resolution of any conflict between a reliability standard and any function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission applicable to a transmission organization. Such transmission organization shall continue to comply with such function, rule, order, tariff, rate schedule or agreement accepted, approved, or ordered by the Commission until –

> "(A) the Commission finds a conflict exists between a reliability standard and any such provision;
>
> "(B) the Commission orders a change to such provision pursuant to section 206 of this part; and

"(C) the ordered change becomes effective under this part.

If the Commission determines that a reliability standard needs to be changed as a result of such a conflict, it shall order the ERO to develop and file with the Commission a modified reliability standard under paragraph (4) or (5) of this subsection.

"(e) ENFORCEMENT. – (1) The ERO may impose, subject to paragraph (2), a penalty on a user or owner or operator of the bulk-power system for a violation of a reliability standard approved by the Commission under subsection (d) if the ERO, after notice and an opportunity for a hearing –

"(A) finds that the user or owner or operator has violated a reliability standard approved by the Commission under sub-section (d); and

"(B) files notice and the record of the proceeding with the Commission.

"(2) A penalty imposed under paragraph (1) may take effect not earlier than the 31st day after the ERO files with the Commission notice of the penalty and the record of proceedings. Such penalty shall be subject to review by the Commission, on its own motion or upon application by the user, owner or operator that is the subject of the penalty filed within 30 days after the date such notice is filed with the Commission. Application to the Commission for review, or the initiation of review by the Commission on its own motion, shall not operate as a stay of such penalty unless the Commission otherwise orders upon its own motion or upon application by the user, owner or operator that is the subject of such penalty.

In any proceeding to review a penalty imposed under paragraph (1), the Commission, after notice and opportunity for hearing (which hearing may consist solely of the record before the ERO and opportunity for the presentation of supporting reasons to affirm, modify, or set aside the penalty), shall by order affirm, set aside, reinstate, or modify the penalty, and, if appropriate, remand to the ERO for further proceedings. The Commission shall implement expedited procedures for such hearings.

"(3) On its own motion or upon complaint, the Commission may order compliance with a reliability standard and may impose a penalty against a user or owner or operator of the bulk-power system if the Commission finds, after notice and opportunity for a hearing, that the user or owner or operator of the bulk-power system has engaged or is about to engage in any acts or practices that constitute or will constitute a violation of a reliability standard.

"(4) The Commission shall issue regulations authorizing the ERO to enter into an agreement to delegate authority to a regional entity for the purpose of proposing reliability standards to the ERO and enforcing reliability standards under paragraph (1) if –

"(A) the regional entity is governed by –

"(i) an independent board;

"(ii) a balanced stakeholder board; or

"(iii) a combination independent and balanced stakeholder board.

"(B) the regional entity otherwise satisfies the provisions of subsection (c)(1) and (2); and

"(C) the agreement promotes effective and efficient administration of bulk-power system reliability.

The Commission may modify such delegation. The ERO and the Commission shall rebuttably presume that a proposal for delegation to a regional entity organized on an Interconnection-wide basis promotes effective and efficient administration of bulk-power system reliability and should be approved. Such regulation may provide that the Commission may assign the ERO's authority to enforce reliability standards under paragraph (1) directly to a regional entity consistent with the requirements of this paragraph.

"(5) The Commission may take such action as is necessary or appropriate against the ERO or a regional entity to ensure compliance with a reliability standard or any Commission order affecting the ERO or a regional entity.

"(6) Any penalty imposed under this section shall bear a reasonable relation to the seriousness of the violation and shall take into consideration the efforts of such user, owner, or operator to remedy the violation in a timely manner.

"(f) CHANGES IN ELECTRIC RELIABILITY ORGANIZATION RULES. – The Electric Reliability Organization shall file with the Commission for approval any proposed rule or proposed rule change, accompanied by an explanation of its basis and purpose. The Commission, upon its own motion or complaint, may

propose a change to the rules of the ERO. A proposed rule or proposed rule change shall take effect upon a finding by the Commission, after notice and opportunity for comment, that the change is just, reasonable, not unduly discriminatory or preferential, is in the public interest, and satisfies the requirements of subsection (c).

"(g) RELIABILITY REPORTS. – The ERO shall conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.

"(h) COORDINATION WITH CANADA AND MEXICO. – The President is urged to negotiate international agreements with the governments of Canada and Mexico to provide for effective compliance with reliability standards and the effectiveness of the ERO in the United States and Canada or Mexico.

"(i) SAVINGS PROVISIONS. – (1) The ERO shall have authority to develop and enforce compliance with reliability standards for only the bulk-power system.

"(2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.

"(3) Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, except that the State of New York may establish

rules that result in greater reliability within that State, as long as such action does not result in lesser reliability outside the State than that provided by the reliability standards.

"(4) Within 90 days of the application of the Electric Reliability Organization or other affected party, and after notice and opportunity for comment, the Commission shall issue a final order determining whether a State action is inconsistent with a reliability standard, taking into consideration any recommendation of the ERO.

"(5) The Commission, after consultation with the ERO and the State taking action, may stay the effectiveness of any State action, pending the Commission's issuance of a final order.

"(j) REGIONAL ADVISORY BODIES. – The Commission shall establish a regional advisory body on the petition of at least two-thirds of the States within a region that have more than one-half of their electric load served within the region. A regional advisory body shall be composed of one member from each participating State in the region, appointed by the Governor of each State, and may include representatives of agencies, States, and provinces outside the United States. A regional advisory body may provide advice to the Electric Reliability Organization, a regional entity, or the Commission regarding the governance of an existing or proposed regional entity within the same region, whether a standard proposed to apply within the region is just, reasonable, not unduly discriminatory or preferential, and in the public interest, whether fees proposed to be assessed within the region are just, reasonable, not

unduly discriminatory or preferential, and in the public interest and any other responsibilities requested by the Commission. The Commission may give deference to the advice of any such regional advisory body if that body is organized on an Interconnection-wide basis.

"(k) ALASKA AND HAWAII. – The provisions of this section do not apply to Alaska or Hawaii.".

(b) STATUS OF ERO. – The Electric Reliability Organization certified by the Federal Energy Regulatory Commission under section 215(c) of the Federal Power Act and any regional entity delegated enforcement authority pursuant to section 215(e)(4) of that Act are not departments, agencies, or instrumentalities of the United States Government.

(c) ACCESS APPROVALS BY FEDERAL AGENCIES. – Federal agencies responsible for approving access to electric transmission or distribution facilities located on lands within the United States shall, in accordance with applicable law, expedite any Federal agency approvals that are necessary to allow the owners or operators of such facilities to comply with any reliability standard, approved by the Commission under section 215 of the Federal Power Act, that pertains to vegetation management, electric service restoration, or resolution of situations that imminently endanger the reliability or safety of the facilities.

CONN. GEN. STAT. (2009)

§ 16-19aa. Excess generating capacity. Exclusion of costs associated with. Return on and depreciation of unrecovered investment in generating facilities

(a) During each proceeding on a rate amendment under section 16-19 proposed by an electric public service company, as defined in section 16-1, having more than seventy-five thousand customers, the Department of Public Utility Control shall (1) review the facilities utilized by the company for the generation and transmission of electricity, (2) determine the level of the company's reserve capacity, (3) determine the company's net reserve capacity by making such adjustments as the department determines appropriate to the level of the company's reserve capacity determined under subdivision (2) of this subsection based on: (A) The reduction of the company's reserve capacity requirement resulting from conservation and load management measures taken by the company and from any other programs or measures undertaken by the company promoting the state's energy policy since January 1, 1986, (B) the capacity of the company's interest in hydroelectric and other renewable resource facilities placed in service after June 1, 1986, (C) the capacity provided to the company by qualifying facilities and resource recovery facilities, (D) any increases of the company's capacity after June 1, 1986, resulting from programs or measures undertaken by the company to implement the state's energy and other policy, (E) the reduction in the

company's reserve capacity requirement attributable to electrical interconnections between New England electric companies and other electric systems outside New England approved by the department, and (F) such other capacity adjustments, which may include adjustments previously recognized by the department, as the department deems appropriate, (4) determine the level of reserve capacity which would provide a net economic benefit to customers of the company, provided the department shall also consider the New England Power Pool reliability standard, the state energy policy as stated in section 16a-35k and any other factors which the department deems appropriate and adjust such level accordingly and (5) exclude from the company's rates, in a manner which shall provide the optimal short-term and long-term benefits to customers of the company, the costs associated with generating facilities which provide net reserve capacity in excess of the level, including any adjustments, determined by the department under subdivision (4) of this section.

(b) The department shall permit the company to continue to recover a return on, and depreciation of, its unrecovered investment in generating facilities previously included in such company's rate base on that portion of a facility determined by the department to be temporarily or permanently retired from service because of capacity, programs or actions that result in deductions from reserve capacity pursuant to subdivision (3) of subsection (a) of this section. Costs incurred to retire such facilities, temporarily or

permanently, and prudently incurred continuing costs associated with temporarily retired facilities shall also be recognized as operating costs of the company. The department's determination shall consider the potential for the sale of energy or capacity, or both, from the facilities temporarily or permanently retired.

(c) Nothing in this section shall impair any settlement agreement the department approves prior to June 20, 1991, or arising out of any proceeding pending before the department as of that date.

(d) The Department of Public Utility Control shall, in any rate proceeding held pursuant to section 16-19 or 16-19a, examine the nuclear generating capacity of any electric public service company.

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§ 16-19ss. Solicitations for the provision of temporary electric generation facilities

(a) The Department of Public Utility Control may, from July 1, 2003, to January 1, 2008, inclusive, determine, by an affirmative vote of four commissioners of the Public Utilities Control Authority, that (1) safe, adequate and reasonably priced electricity is not available on the wholesale market; (2) additional temporary electric generation facilities will result in reductions in federally mandated congestion costs for which the ratepayers of the state are responsible; and (3) the prices and costs specified in subdivision (2) of this subsection will exceed the cost of investment in

temporary electric generation facilities. Such determination shall be in writing and shall state the reasons supporting the determination.

(b) Upon issuing a determination pursuant to subsection (a) of this section, the department shall hold a contested case proceeding, in accordance with the provisions of chapter 54, to develop a request for proposal to solicit the provision of such additional temporary electric generation facilities, containing such terms and conditions that will best serve the interests of the public. The request for proposal process shall be designed to ensure fairness and full participation by all qualified responders.

(c) The department may negotiate for terms and conditions necessary to conclude a transaction with one or more entities responding to a request for proposal, after notice to all entities that responded. The department shall base its decision to conclude a transaction on the best interest of the public and ratepayers.

(d) Nothing in this section shall be construed to allow an electric distribution company to own, operate, lease or control any facility or asset that generates electricity, or retain any interest in such facility or asset as part of any transaction concluded pursuant to this section, except as provided in subsection (e) of section 16-244e and sections 16-43d, 16-243m, 16-243u, 16a-3b and 16a-3c.

§ 16-50p. Certification proceeding decisions: Timing, opinion, factors considered. Telecommunications and community antenna television facilities: Additional factors considered, conditions. Modification of location. Amendment proceeding decisions. Service and notice. "Public need" defined

(a)(1) In a certification proceeding, the council shall render a decision upon the record either granting or denying the application as filed, or granting it upon such terms, conditions, limitations or modifications of the construction or operation of the facility as the council may deem appropriate.

(2) The council's decision shall be rendered in accordance with the following:

(A) Not later than twelve months after the deadline for filing an application following the request for proposal process for a facility described in subdivision (1) or (2) of subsection (a) of section 16-50i or subdivision (4) of said subsection (a) if the application was incorporated in an application concerning a facility described in subdivision (1) of said subsection (a);

(B) Not later than one hundred eighty days after the deadline for filing an application following the request for proposal process for a facility described in subdivision (4) of said subsection (a), and an application concerning a facility described in subdivision (3)

of said subsection (a), provided such time periods may be extended by the council by not more than one hundred eighty days with the consent of the applicant; and

(C) Not later than one hundred eighty days after the filing of an application for a facility described in subdivision (5) or (6) of said subsection (a), provided such time period may be extended by the council by not more than one hundred eighty days with the consent of the applicant.

(3) The council shall file, with its order, an opinion stating in full its reasons for the decision. The council shall not grant a certificate, either as proposed or as modified by the council, unless it shall find and determine:

(A) Except as provided in subsection (c) of this section, a public need for the facility and the basis of the need;

(B) The nature of the probable environmental impact of the facility alone and cumulatively with other existing facilities, including a specification of every significant adverse effect, including, but not limited to, electromagnetic fields that, whether alone or cumulatively with other effects, on, and conflict with the policies of the state concerning, the natural environment, ecological balance, public health and safety, scenic, historic and recreational values, forests and parks, air and water purity and fish, aquaculture and wildlife;

(C) Why the adverse effects or conflicts referred to in subparagraph (B) of this subdivision are not sufficient reason to deny the application;

(D) In the case of an electric transmission line, (i) what part, if any, of the facility shall be located overhead, (ii) that the facility conforms to a long-range plan for expansion of the electric power grid of the electric systems serving the state and interconnected utility systems and will serve the interests of electric system economy and reliability, and (iii) that the overhead portions, if any, of the facility are cost effective and the most appropriate alternative based on a life-cycle cost analysis of the facility and underground alternatives to such facility, are consistent with the purposes of this chapter, with such regulations or standards as the council may adopt pursuant to section 16-50t, including, but limited to, the council's best management practices for electric and magnetic fields for electric transmission lines and with the Federal Power Commission "Guidelines for the Protection of Natural Historic Scenic and Recreational Values in the Design and Location of Rights-of-Way and Transmission Facilities" or any successor guidelines and any other applicable federal guidelines and are to be contained within an area that provides a buffer zone that protects the public health and safety, as determined by the council. In establishing such buffer zone, the council shall take into consideration, among other things, residential areas, private or public schools, licensed child day

care facilities, licensed youth camps or public playgrounds adjacent to the proposed route of the overhead portions and the level of the voltage of the overhead portions and any existing overhead transmission lines on the proposed route. At a minimum, the existing right-of-way shall serve as the buffer zone;

(E) In the case of an electric or fuel transmission line, that the location of the line will not pose an undue hazard to persons or property along the area traversed by the line;

(F) In the case of an application that was heard under a consolidated hearing process with other applications that were common to a request for proposal, that the facility proposed in the subject application represents the most appropriate alternative among such applications based on the findings and determinations pursuant to this subsection; and

(G) In the case of a facility described in subdivision (6) of subsection (a) of section 16-50i that is proposed to be installed on land under agricultural restriction, as provided in section 22-26cc, that the facility will not result in a material decrease of acreage and productivity of the arable land.

(b)(1) Prior to granting an applicant's certificate for a facility described in subdivision (5) or (6) of section 16-50i, the council shall examine, in addition to its consideration of subdivisions (1) to (5), inclusive, of subsection (a) of this section: (A) The feasibility of requiring an applicant to share an existing facility, as

defined in subsection (b) of section 16-50aa, within a technically derived search area of the site of the proposed facility, provided such shared use is technically, legally, environmentally and economically feasible and meets public safety concerns, (B) whether such facility, if constructed, may be shared with any public or private entity which provides telecommunications or community antenna television service to the public, provided such shared use is technically, legally, environmentally and economically feasible at fair market rates, meets public safety concerns, and the parties' interests have been considered and (C) whether the proposed facility would be located in an area of the state which the council, in consultation with the Department of Environmental Protection and any affected municipalities, finds to be a relatively undisturbed area that possesses scenic quality of local, regional or state-wide significance. The council may deny an application for a certificate if it determines that (i) shared use under the provisions of subparagraph (A) of this subdivision is feasible, (ii) the applicant would not cooperate relative to the future shared use of the proposed facility, or (iii) the proposed facility would substantially affect the scenic quality of its location and no public safety concerns require that the proposed facility be constructed in such a location.

(2) When issuing a certificate for a facility described in subdivision (5) or (6) of subsection (a) of section 16 50i, the council may impose such reasonable

conditions as it deems necessary to promote immediate and future shared use of such facilities and avoid the unnecessary proliferation of such facilities in the state. The council shall, prior to issuing a certificate, provide notice of the proposed facility to the municipality in which the facility is to be located. Upon motion of the council, written request by a public or private entity which provides telecommunications or community antenna television service to the public or upon written request by an interested party, the council may conduct a preliminary investigation to determine whether the holder of a certificate for such a facility is in compliance with the certificate. Following its investigation, the council may initiate a certificate review proceeding, which shall include a hearing, to determine whether the holder of a certificate for such a facility is in compliance with the certificate. In such proceeding, the council shall render a decision and may issue orders which it deems necessary to compel compliance with the certificate, which orders may include, but not be limited to, revocation of the certificate. Such orders may be enforced in accordance with the provisions of section 16-50u.

(c)(1) The council shall not grant a certificate for a facility described in subdivision (3) of subsection (a) of section 16-50i, either as proposed or as modified by the council, unless it finds and determines a public benefit for the facility.

(2) The council shall not grant a certificate for a facility described in subdivision (1) of subsection (a) of section 16-50i which is substantially underground or underwater except where such facilities interconnect with existing overhead facilities, either as proposed or as modified by the council, unless it finds and determines a public benefit for the facility, in the case of such facility that is substantially underground, and a public need for such facility, in the case of such facility that is substantially underwater.

(3) For purposes of subparagraph (A) of this subdivision, a public benefit exists if such a facility is necessary for the reliability of the electric power supply of the state or for the development of a competitive market for electricity and a public need exists if such facility is necessary for the reliability of the electric power supply of the state.

(4) Any application for an electric transmission line with a capacity of three hundred forty-five kilovolts or more that is filed on or after May 1, 2003, and that proposes the underground burial of such line in all residential areas and overhead installation of such line in industrial and open space areas affected by such proposal shall have a rebuttable presumption of meeting a public benefit for such facility if the facility is substantially underground, and meeting a public need for such facility if the facility is substantially above ground. Such presumption may be overcome by evidence submitted by a party or intervenor to the satisfaction of the council.

(d) If the council determines that the location of all or a part of the proposed facility should be modified, it may condition the certificate upon such modification, provided the municipalities, and persons residing or located in such municipalities, affected by the modification shall have had notice of the application as provided in subsection (b) of section 16-50*l*.

(e) In an amendment proceeding, the council shall render a decision within ninety days of the filing of the application or adoption of the resolution initiating the proceeding. The council shall file an opinion with its order stating its reasons for the decision. The council's decision shall include the findings and determinations enumerated in subsection (a) of this section which are relevant to the proposed amendment.

(f) A copy of the order and opinion issued therewith shall be served upon each party and a notice of the issuance of the order and opinion shall be published in such newspapers as will serve substantially to inform the public of the issuance of such order and opinion. The name and address of each party shall be set forth in the order.

(g) In making its decision as to whether or not to issue a certificate, the council shall in no way be limited by the fact that the applicant may already have acquired land or an interest therein for the purpose of constructing the facility which is the subject of its application.

(h) For purposes of this section, a public need exists for an energy facility if such facility is necessary for the reliability of the electric power supply of the state.

(i) For a facility described in subdivision (1) of subsection (a) of section 16-50i, with a capacity of three hundred forty-five kilovolts or greater, there shall be a presumption that a proposal to place the overhead portions, if any, of such facility adjacent to residential areas, private or public schools, licensed child day care facilities, licensed youth camps or public playgrounds is inconsistent with the purposes of this chapter. An applicant may rebut this presumption by demonstrating to the council that it will be technologically infeasible to bury the facility. In determining such infeasibility, the council shall consider the effect of burying the facility on the reliability of the electric transmission system of the state and whether the cost of any contemplated technology or design configuration may result in an unreasonable economic burden on the ratepayers of the state.

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§ 16-50r. Report of forecast of loads and resources. Confidential Information. Regulations. Investigation of life-cycle costs for overhead and underground transmission lines: Scope, hearings, consultants, assessment

(a) Every person engaged in electric transmission services, as defined in section 16-1, electric generation services, as defined in said section, or electric distribution services, as defined in said section

generating electric power in the state utilizing a generating facility with a capacity greater than one megawatt, shall, annually, on or before March first, file a report on a forecast of loads and resources which may consist of an update of the previous year's report with the council for its review. The report shall cover the ten-year forecast period beginning with the year of the report. Upon request, the report shall be made available to the public. The report shall include, as applicable: (1) A tabulation of estimated peak loads, resources and margins for each year; (2) data on energy use and peak loads for the five preceding calendar years; (3) a list of existing generating facilities in service; (4) a list of scheduled generating facilities for which property has been acquired, for which certificates have been issued and for which certificate applications have been filed; (5) a list of planned generating units at plant locations for which property has been acquired, or at plant locations not yet acquired, that will be needed to provide estimated additional electrical requirements, and the location of such facilities; (6) a list of planned transmission lines on which proposed route reviews are being undertaken or for which certificate applications have already been filed; (7) a description of the steps taken to upgrade existing facilities and to eliminate overhead transmission and distribution lines in accordance with the regulations and standards described in section 16-50t; and (8) for each private power producer having a facility generating more than one megawatt and from whom the person furnishing the report has purchased electricity during the preceding

calendar year, a statement including the name, location, size and type of generating facility, the fuel consumed by the facility and the by-product of the consumption. Confidential, proprietary or trade secret information provided under this section may be submitted under a duly granted protective order. The council may adopt regulations, in accordance with the provisions of chapter 54, that specify the expected filing requirements for persons that transmit electric power in the state, electric distribution companies, and persons that generate electric power in the state utilizing a generating facility with a capacity of greater than one megawatt. Until such regulations are adopted, persons that transmit electric power in the state shall file reports pursuant to this section that include the information requested in subdivisions (6) and (7) of this subsection; electric distribution companies in the state shall file reports pursuant to this section that include the information requested in subdivisions (1), (2), (7) and (8) of this subsection; persons that generate electric power in the state utilizing a generating facility with a capacity greater than one megawatt shall file reports pursuant to this section that include the information requested in subdivisions (3), (4), (5) and (8) of this subsection. The council shall hold a public hearing on such filed forecast reports annually. The council shall conduct a review in an executive session of any confidential, proprietary or trade secret information submitted under a protective order during such a hearing. At least one session of such hearing shall be

held after six-thirty p.m. Upon reviewing such forecast reports, the council may issue its own report assessing the overall status of loads and resources in the state. If the council issues such a report, it shall be made available to the public and shall be furnished to each member of the joint standing committee of the General Assembly having cognizance of matters relating to energy and technology, any other member of the General Assembly making a written request to the council for the report and such other state and municipal bodies as the council may designate.

(b) On October 1, 1994, and not less than once every five years thereafter, the council shall establish a proceeding to investigate and determine life-cycle costs for both overhead and underground transmission line alternatives. The council shall determine the schedule and scope of the investigation at a publicly noticed meeting held not earlier than ninety days preceding the first public hearing on the matter. The scope of the investigation shall include, but not be limited to, an inquiry of all relevant life-cycle costs, relative reliability, constraints concerning access and construction, potential damage to the environment and compatibility with the existing electric supply system. As part of the investigation the council shall hold public hearings which shall afford all interested parties opportunity to be heard. At least one public hearing shall be held after six-thirty p.m.

(c) An investigation conducted pursuant to subsection (b) of this section may include the retention of consultants, manufacturers and other experts necessary for the council to objectively determine the range of life-cycle costs of such alternatives. No such consultant, manufacturer or expert shall have any financial interest in, or, in the twelve months preceding the investigation, have engaged in any business, employment or professional activity for compensation with a corporation, company, association, joint stock association, partnership or person, or lessee thereof, owning, leasing, maintaining, operating, managing or controlling poles, wires, conduits or other fixtures, along public highways or streets, for the transmission or distribution of electric current for sale for light, heat or power within the state, or with a person, firm or corporation which manufactures such poles, wires, conduits or other fixtures. The council shall apportion and assess its expenses for consultants, hearing facilities, stenographic reports and other reasonable and necessary expenses of conducting such an investigation among those persons, firms and corporations having gross revenues from the retail sale of electric power in excess of one hundred thousand dollars during the preceding calendar year. The council shall assess each such person, firm or corporation in proportion of its gross revenues to the aggregate gross revenues of all such persons, firms and corporations. Each person, firm or corporation subject to an assessment shall pay its assessed amount not later than thirty days after receiving notice of its assessment or as specified by

the council. Prior to incurring expenses for which assessments shall be made under this subsection, the council shall review the anticipated expenses at a public meeting, notice of which shall be given to each person, firm or corporation subject to an assessment. A person, firm or corporation may object to an assessment made pursuant to this subsection by filing with the council, not later than thirty days after receiving notice of its assessment, a petition stating the amount of the assessment to which it objects and the grounds upon which it claims such assessment is excessive, erroneous, unlawful or invalid. Upon the request of the petitioner, the council shall hold a hearing. After reviewing the company's petition and testimony, if any, the council shall issue an order in accordance with its findings. The petitioner shall pay the council the amount indicated in the order not later than thirty days after the date of the order.

(d) The council shall remit all payments received pursuant to this section to the state treasurer for deposit in the Siting Council Fund. Such payments shall be accounted for as expenses recovered from electric power suppliers. All payments made under this section shall be in addition to any taxes payable to the state under chapters 211, 212, 212a and 219.

(e) An assessment unpaid on the due date or any portion of an assessment withheld after the due date under this section shall be subject to interest at the rate of one and one-fourth per cent per month or fraction thereof.

§ 16-244. Electric deregulation; findings and declarations

The General Assembly finds and declares that:

(1) The provision of affordable, safe and reliable electricity is key to the continuing growth of this state and to the health, safety and general welfare of its residents;

(2) Rates for electricity in this state and in the region are higher than the national average;

(3) Changes in generating technology now enable the provision of electric service at much lower rates than are currently being charged in Connecticut and competitive market forces can play a role in the reduction of Connecticut rates;

(4) It is in the best interest of the state to reduce rates for electricity to all customer classes, to prevent cross subsidization among customer classes and to allow for the competitive generation of electricity while retaining a regulated distribution system to ensure reliability;

(5) A competitive generation market should allow customers to choose among alternative generation services and allow customers a reasonable and fair opportunity to self-generate and interconnect;

(6) Those public policy measures under current law, including, but not limited to, those protecting customers under the winter moratorium and hardship provisions as well as conservation measures and incentives for using renewable energy sources, should be preserved;

(7) State regulations should encourage and allow for a sufficient number of in-state generating facilities to ensure an adequate and reliable power supply within the state and ensure development of a truly competitive generation market;

(8) The assurance of safe, reliable and available electric service to all customers in a uniform and equitable manner is an essential governmental objective and a restructured electric market must provide adequate safeguards to assure universal service and customer service protections;

(9) The generation of electricity must be achieved in a manner that does not endanger the public health or safety and that minimizes negative environmental impacts;

(10) The restructuring of the electric industry may result in a reduction in staffing levels at Connecticut generation facilities and those workers adversely affected by such restructuring should be protected;

(11) The current method of providing electric service has involved a balancing of costs, risks and rewards for electric utilities and their customers, and therefore the transition to a competitive generation market, including the determination of stranded costs, should be based on the principles of fairness and reasonableness and the result of a balance of the interests of electric customers, electric utilities and the public at large; and

(12) It is in the best interest of the state for all customers to use electricity as efficiently as possible.

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§ 16a-3a. Comprehensive plan for energy resource procurement

(a) The electric distribution companies, in consultation with the Connecticut Energy Advisory Board, established pursuant to section 16a-3, shall review the state's energy and capacity resource assessment and develop a comprehensive plan for the procurement of energy resources, including, but not limited to, conventional and renewable generating facilities, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies to meet the projected requirements of their customers in a manner that minimizes the cost of such resources to customers over time and maximizes consumer benefits consistent with the state's environmental goals and standards.

(b) On or before January 1, 2008, and annually thereafter, the companies shall submit to the Connecticut Energy Advisory Board an assessment of (1) the energy and capacity requirements of customers for the next three, five and ten years, (2) the manner of how best to eliminate growth in electric demand, (3) how best to level electric demand in the state by reducing peak demand and shifting demand to off-peak periods, (4) the impact of current and projected environmental standards, including, but not limited to, those related to greenhouse gas emissions and the federal Clean Air Act goals and how different resources could help achieve those standards and goals, (5) energy security and economic risks associated with potential energy resources, and (6) the estimated lifetime cost and availability of potential energy resources.

(c) Resource needs shall first be met through all available energy efficiency and demand reduction resources that are cost-effective, reliable and feasible. The projected customer cost impact of any demand-side resources considered pursuant to this subsection shall be reviewed on an equitable bases [sic] with nondemand-side resources. The procurement plan shall specify (1) the total amount of energy and capacity resources needed to meet the requirements of all customers, (2) the extent to which demand-side measures, including efficiency, conservation, demand response and load management can cost-effectively meet these needs, (3) needs for generating capacity and transmission and distribution improvements,

(4) how the development of such resources will reduce and stabilize the costs of electricity to consumers, and (5) the manner in which each of the proposed resources should be procured, including the optimal contract periods for various resources.

(d) The procurement plan shall consider: (1) Approaches to maximizing the impact of demand-side measures; (2) the extent to which generation needs can be met by renewable and combined heat and power facilities; (3) the optimization of the use of generation sites and generation portfolio existing within the state; (4) fuel types, diversity, availability, firmness of supply and security and environmental impacts thereof, including impacts on meeting the state's greenhouse gas emission goals; (5) reliability, peak load and energy forecasts, system contingencies and existing resource availabilities; (6) import limitations and the appropriate reliance on such imports; and (7) the impact of the procurement plan on the costs of electric customers.

(e) The board, in consultation with the regional independent system operator, shall review and approve or review, modify and approve the proposed procurement plan as submitted not later than one hundred twenty days after receipt. For calendar years 2009 and thereafter, the board shall conduct such review not later than sixty days after receipt. For the purpose of reviewing the plan, the Commissioners of Transportation and Agriculture and the chairperson of the Public Utilities Control Authority, or their

respective designees, shall not participate as members of the board. The electric distribution companies shall provide any additional information requested by the board that is relevant to the consideration of the procurement plan. In the course of conducting such review, the board shall conduct a public hearing, may retain the services of a third-party entity with experience in the area of energy procurement and may consult with the regional independent system operator. The board shall submit the reviewed procurement plan, together with a statement of any unresolved issues, to the Department of Public Utility Control. The department shall consider the procurement plan in an uncontested proceeding and shall conduct a hearing and provide an opportunity for interested parties to submit comments regarding the procurement plan. Not later than one hundred twenty days after submission of the procurement plan, the department shall approve, or modify and approve, the procurement plan. For calendar years 2009 and thereafter, the department shall approve, or modify and approve, said procurement plan not later than sixty days after submission.

(f) On or before September 30, 2009, and every two years thereafter, the Department of Public Utility Control shall report to the joint standing committees of the General Assembly having cognizance of matters relating to energy and the environment regarding goals established and progress toward

implementation of the procurement plan established pursuant to this section, as well as any recommendations for the process.

(g) All electric distribution companies' costs associated with the development of the resource assessment and the development of the procurement plan shall be recoverable through the systems benefits charge.

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§ 16a-3b. Implementation of the procurement plan

(a) The Department of Public Utility Control shall oversee the implementation of the procurement plan approved by the Department of Public Utility Control pursuant to section 16a-3a. The electric distribution companies shall implement the demand-side measures, including, but not limited to, energy efficiency, load management, demand response, combined heat and power facilities, distributed generation and other emerging energy technologies, specified in said procurement plan through the comprehensive conservation and load management plan prepared pursuant to section 16-245m for review by the Energy Conservation Management Board. The electric distribution companies shall submit proposals to appropriate regulatory agencies to address transmission and distribution upgrades as specified in said procurement plan.

(b) If the procurement plan specifies the construction of a generating facility, the department shall develop and issue a request for proposals, shall publish such request for proposals in one or more newspapers or periodicals, as selected by the department, and shall post such request for proposals on its web site. Pursuant to a nondisclosure agreement, the department shall make available to the Office of Consumer Counsel and the Attorney General all confidential bid information it receives pursuant to this subsection, provided the bids and any analysis of such bids shall not be subject to disclosure under the Freedom of Information Act. Three months after the department issues a final decision, it shall make available all financial bid information, provided such information regarding the bidders not selected be presented in a manner that conceals the identities of such bidders.

(1) On and after July 1, 2008, an electric distribution company may submit proposals in response to a request for proposals on the same basis as other respondents to the solicitation. A proposal submitted by an electric distribution company shall include its full projected costs such that any project costs recovered from or defrayed by ratepayers are included in the projected costs. An electric distribution company submitting any such bid shall demonstrate to the satisfaction of the department that its bid is not supported in any form of cross subsidization by affiliated entities. If the department approves such

electric distribution company's proposal, the costs and revenues of such proposal shall not be included in calculating such company's earning for purposes of, or in determining whether its rates are just and reasonable under, sections 16-19, 16-19a and 16-19e. An electric distribution company shall not recover more than the full costs identified in any approved proposal. Affiliates of the electric distribution company may submit proposals pursuant to section 16-244h, regulations adopted pursuant to section 16-244h and other requirements the department may impose.

(2) If the department selects a nonelectric distribution company proposal, an electric distribution company shall, within thirty days of the selection of a proposal by the department, negotiate in good faith the final terms of a contract with a generating facility and shall apply to the department for approval of such contract. Upon department approval, the electric distribution company shall enter into such contract.

(3) The department shall determine the appropriate manner of cost recovery for proposals selected pursuant to this section.

(4) The department may retain the services of a third-party entity with expertise in the area of energy procurement to oversee the development of the request for proposals and to assist the department in its approval of proposals pursuant to this section. The

reasonable and proper expenses for retaining such third-party entity shall be recoverable through the generation services charge.

(c) The electric distribution companies shall issue requests for proposals to acquire any other resource needs not identified in subsection (a) or (b) of this section but specified in the procurement plan approved by the Department of Public Utility Control pursuant to section 16a-3a. Such requests for proposals shall be subject to approval by the department.

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§ 16a-3c. Electric distribution companies' plans to build electric generation facilities

(a) On and after July 1, 2009, if the Department of Public Utility Control does not receive and approve proposals pursuant to the requests for proposals processes, pursuant to section 16a-3b, sufficient to reach the goal set by the plan approved pursuant to section 16a-3a, the department may order an electric distribution company to submit for the department's review in a contested case proceeding, in accordance with chapter 54, a proposal to build and operate an electric generation facility in the state. An electric distribution company shall be eligible to recover its prudently incurred costs consistent with the principles set forth in section 16-19e for any generation project approved pursuant to this section.

(b) On or before January 1, 2008, the department shall initiate a contested case proceeding to determine the costs and benefits of the state serving as the builder of last resort for the shortfall of megawatts from said request for proposal process.

ME. REV. STAT. ANN. (2008)

Tit. 35-A, § 3210-D. Resource plan

The commission shall adopt by rule a long-term plan for electric resource adequacy for this State to ensure grid reliability and the provision or availability of electricity to consumers at the lowest cost.

After final adoption of rules under this section, the commission shall take any necessary action within its authority under this Title to support achievement of the objectives of the plan. Rules adopted under this section are major substantive rules as defined in Title 5, chapter 375, subchapter 2-A.

MASS. GEN. LAWS (2009)

Ch. 164, § 69I. Long-range forecasts of electric and gas companies; filing; hearings; approval

The department shall approve or reject long-range plans; provided, however, that a long-range plan submitted in conjunction with a petition to construct a facility may be referred to the board for review and approval or rejection in accordance with section sixty-nine J. Every electric company, except municipal corporations authorized to operate a municipal lighting plant under the provisions of sections thirty-four to thirty-six, inclusive, shall file with the department a long-range forecast with respect to the electric power needs and requirements of its market area, taking into account wholesale bulk power sales or purchases or other cooperative arrangements with other electric companies, for the ensuing ten-year period. Such forecast shall be filed at least every two years.

Every gas company, except municipal corporations authorized to operate a municipal gas plant under the provisions of sections thirty-four to thirty-six, inclusive, shall file with the department a long-range forecast with respect to the gas requirements of its market area, taking into account wholesale bulk gas sales or purchases or other cooperative arrangements with other gas companies, for the ensuing five-year period. Said forecast of gas requirements shall consist of the gas sendout necessary to serve projected firm customers, and the available supplies, for the ensuing five-year period. Such forecast shall be filed at least every two years.

As regional plans covering longer time periods are developed, they shall be filed with the department. Neither said department, the board, nor any other person, in taking any action pursuant to sections 69*I* to 69J 1/4, inclusive, shall be subject to any of the provisions of sections 61 to 62H, inclusive, of chapter 30.

Said forecasts shall include, in such form and detail as the department shall prescribe, the following information:

(1) A description of all then existing agreements with other electric or gas companies for joint planning or joint forecasting of electric power or gas needs and the purchase or sale of electric power or gas or reserve capacity.

(2) A forecast of the electric power needs or gas requirements for its market area, taking into account wholesale bulk power or gas sales or purchases, or other co-operative arrangements with other utilities and energy policies as adopted by the commonwealth.

(3) A description of actions planned to be taken by the company which will affect capacity to meet such needs or requirements, including, but not limited to: expansion, reduction or removal of existing facilities; construction or acquisition of additional facilities; a description of alternatives to planned action such as other methods of generating, manufacturing or storing, other site locations, other sources of electrical power or gas, including facilities which operate on solar or geothermal energy and wind or facilities

which operate on the principle of cogeneration or hydrogeneration, and no additional electrical power or gas; a reduction of requirements through load management; a description of the environmental impact of each proposed facility; provided, however, that the above provisions shall not apply to facilities which have been approved as part of a previous long-range forecast or supplement thereto. The department shall after public notice and a period for comment be empowered to issue and revise its own list of guidelines. A minimum of data shall be required by these guidelines from the applicant for review concerning land use impact, water resource impact, air quality impact, solid waste impact, radiation impact and noise impact.

The department or board shall conduct a public hearing on every long-range forecast within six months of the filing thereof. Such hearing shall be an adjudicatory proceeding under the provisions of chapter thirty A. The department or board shall within twelve months from the date of filing approve a long-range forecast if it meets the following requirements: all information relating to current activities, environmental impacts, facilities agreements and energy policies as adopted by the commonwealth is substantially accurate and complete; projections of the demand for electric power, or gas requirements and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods and include an adequate consideration of

conservation and load management; provided, however, that the department or board shall not require in any gas forecast or hearing conducted thereon the presentation of information relative to the demand for gas; projections relating to service area, facility use and pooling or sharing arrangements are consistent with such forecasts of other companies subject to this chapter as may have already been approved and reasonable projections of activities of other companies in the New England area; plans for the expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth; and are consistent with the policies stated in section sixty-nine H to provide a necessary energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost.

If the department or board determines the standards set forth above have not been met, it shall within twelve months of the date of filing reject in whole or in part the long-range forecast setting forth in writing its reasons for such rejections, or approve the long-range forecast subject to stated conditions. In event of rejection or conditioned approval, the applicant or individual company may within six months submit an amended forecast. A public hearing on the amended forecast shall be held on the same terms and conditions applicable to the original forecast.

The authority of the department and board to conduct public hearings under the provisions of this section may be delegated in whole or part to employees of the department. Pursuant to the rules of the department and board, employees of the department shall report back to the department or board with recommended decisions for final action thereon.

The department and the siting board shall prepare and file with the general court, by March first of each year, an annual report for the previous calendar year detailing the substance of all plans and forecasts filed pursuant to this section, any and all actions taken by the department pursuant to implementing the provisions of this section, and an analysis of the reliability and diversity of electric power and gas needs based on such filings with the department and decisions made and issued by the department.

The department is authorized to exempt any electric or gas company from any or all provisions of this section upon a determination by the department and the siting board, after notice and hearing, that an alternative process is in the public interest.

N.H. REV. STAT. ANN. (2009)

§ 162-H:1. Declaration of Purpose

The legislature recognizes that the selection of sites for energy facilities, including the routing of high voltage transmission lines and energy transmission pipelines, will have a significant impact upon the welfare of the population, the location and growth of industry, the overall economic growth of the state, the environment of the state, and the use of natural resources. Accordingly, the legislature finds that it is in the public interest to maintain a balance between the environment and the need for new energy facilities in New Hampshire; that undue delay in the construction of needed facilities be avoided and that full and timely consideration of environmental consequences be provided; that all entities planning to construct facilities in the state be required to provide full and complete disclosure to the public of such plans; and that the state ensure that the construction and operation of energy facilities is treated as a significant aspect of land-use planning in which all environmental, economic, and technical issues are resolved in an integrated fashion, all to assure that the state has an adequate and reliable supply of energy in conformance with sound environmental principles. The legislature, therefore, hereby establishes a procedure for the review, approval, monitoring, and enforcement of compliance in the planning, siting, construction, and operation of energy facilities.

R.I. GEN. LAWS (2008)

§ 42-98-2. Declaration of policy

It shall be the policy of this state to assure that:

(1) The facilities required to meet the energy needs of this and succeeding generations of Rhode Islanders are planned for, considered, and built in a timely and orderly fashion;

(2) Construction, operation, and/or alteration of major energy facilities shall only be undertaken when those actions are justified by long term state and/or regional energy need forecasts;

(3) The energy shall be produced at the least possible cost to the consumer consistent with the objective of ensuring that the construction, operation, and decommissioning of the facility shall produce the fewest possible adverse effects on the quality of the state's environment; most particularly, its land and its wildlife and resources, the health and safety of its citizens, the purity of its air and water, its aquatic and marine life, and its esthetic and recreational value to the public;

(4) The licensure and regulatory authority of the state be consolidated in a single body, which will render the final licensing decision concerning the siting, construction, operation and/or alteration of major energy facilities;

(5) An energy facility planning process shall be created through which the statewide planning program, in conjunction with the division of public utilities and carriers, will be empowered to undertake evaluations and projections of long and short term energy needs, and any other matters that are necessary to establish the state energy plans, goals, and policies. The state planning council shall be authorized and empowered to adopt a long term plan assessing the state's future energy needs and the best strategy for meeting them, as part of the state guide plan by January 1, 1991.

(6) The construction, operation and/or alteration of major energy facilities shall be consistent with the state's established energy plans, goals, and policy.

(7) Before approving the construction, operation and/or alteration of major energy facilities, the board shall determine whether cost effective efficiency and conservation opportunities provide an appropriate alternative to the proposed facility.

(8) The energy facilities siting board shall give priority to energy generation projects based on the degree to which such projects meet, criteria including, but not limited to:

(i) Using renewable fuels, natural gas, or coal processed by "clean coal technology" as their primary fuel;

(ii) Maximizing efficiency;

(iii) Using low levels of high quality water;

(iv) Using existing energy-generation facilities and sites;

(v) Producing low levels of potentially harmful air emissions;

(vi) Producing low levels of wastewater discharge;

(vii) Producing low levels of waste into the solid waste stream; and

(viii) Having dual fuel capacity.

The board shall, within its rules and regulations, provide guidelines and definitions of appropriate standards for the criteria designated in this subsection by January 1, 1991.

VT. STAT. ANN. (2008)

Tit. 30, § 202a. State energy policy

It is the general policy of the state of Vermont:

(1) To assure, to the greatest extent practicable, that Vermont can meet its energy service needs in a manner that is adequate, reliable, secure and sustainable; that assures affordability and encourages the state's economic vitality, the efficient use of energy resources and cost effective demand side management; and that is environmentally sound.

(2) To identify and evaluate on an ongoing basis, resources that will meet Vermont's energy service needs in accordance with the principles of least cost integrated planning; including efficiency, conservation and load management alternatives, wise use of renewable resources and environmentally sound energy supply.